Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

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March 1, 2010

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PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
Kekuanaoa Building, First Floor
465 South King Street
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 2008-0273 – Feed-in Tariff Investigation
<u>Hawaiian Electric Companies' Responses to Information Requests</u>

Attached are the Hawaiian Electric Companies'[1] responses to the information requests on Reliability Standards and Queuing and Interconnection Procedures, submitted by the following parties on February 16, 2010:

- Blue Planet Foundation;
- Division of Consumer Advocacy;
- The Department of Business, Economic Development, and Tourism;
- Hawaii Renewable Energy Alliance;
- The Solar Alliance and Hawaii Solar Energy Association;
- Tawhiri; and
- Zero Emissions Leasing LLC.[2]

Sincerely,

Dean K. Matsuura

Attachments

cc: Service List

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[1] Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited are collectively referred to as the "Hawaiian Electric Companies."
[2] Information requests were submitted on February 11, 2010.

Response to

Blue Planet Foundation's

Information Requests

BP-HECO-IR-10

Ref.: HECO RS Report

The HECO RS Report states that "Due primarily to the high level of existing and planned renewable resource penetration on the MECO and HELCO systems, the studies indicate that there is minimal to no room at this time to accommodate additional renewable resources (FIT or otherwise) without significant curtailment of either existing or planned renewable resources, or a threat to system reliability." *Id.*, Exhibit 1 at 4 (emphasis added).

a. Assuming there is "minimal room" to accommodate additional renewable resources (FIT or otherwise), please identify the quantity of additional renewable resources (FIT or otherwise) which the MEC04 and HELCO grids can accommodate at this time.

b. Please explain the relative proportion, stated as a percentage ranging from 0% to 100%, the above conclusion concerning "minimal to no room" is based on curtailment versus reliability concerns.

HECO Companies Response:

a. For the MECO and HELCO systems, the quantity of additional variable renewable resources (FIT or otherwise) which can be accommodated at this time without significant curtailment of existing or planned renewable resources or impacts on system reliability is difficult to state due to the dynamic nature of an electrical system and the numerous combinations of factors that can influence an electrical system. Variables such as system load, types of firm generation available, regulating reserve requirements and the level of power output from as-available generation on-line all have an affect on generation requirements. Furthermore, as independent islanded systems, there is no capability to export excess generation to avoid over-frequency conditions and curtailment. However, renewable energy from firm, dispatchable resources could potentially be added to the system without additional curtailments if they provide the necessary characteristics that would allow displacement of one of the must-run conventional fossil fuel units. More detailed studies are needed to determine the quantity of additional variable renewables that can be accommodated assuming mitigating technologies are employed. Please see the Hawaiian Electric Companies'

Response to Commission Letter of February 19, 2010, filed February 26, 2010 in this Docket.

b. The conclusion that there is "minimal to no room" is due primarily to curtailment concerns although absent the ability to appropriately curtail resources to maintain system balance, broader system reliability concerns must be addressed. As independent islanded systems, there is no capability to export excess generation to avoid over-frequency conditions and the curtailment of existing and planned as-available renewable generation is required. There are concerns about reliability impacts, as described in Attachments 2, 5, and 6 to the Reliability Standards Report. Due to limited analysis available at this time and recommendations for additional studies to be conducted, a definitive percentage as to the relative proportion of curtailment versus reliability concerns would be difficult to calculate; both concerns must be addressed and contribute to the limited ability of the systems to take significant amounts of additional variable distributed generation.

BP-HECO-IR-11

Ref.: HECO RS Report

The HECO RS Report states that "The impact of this determination is that the integration of FIT resources on the HELCO and MECO systems may have to be temporarily deferred until additional studies can be performed and/or infrastructure developed, so that additional distributed renewable generation can be integrated on these systems without threatening system reliability or causing significant curtailment of other renewable generation." *Id.*, Exhibit I at 4 (emphasis added).

a. Please provide a list for HELCO and a list for MECO identifying and describing (i) the specific "additional studies" to be performed, (ii) the estimated time and cost for any such studies, and (iii) whether and to what extent the substance or results of the "additional studies" may be found in completed and currently existing studies.

b. Please provide a list for HELCO and a list for MECO identifying and describing (i) the specific additional "infrastructure" to be developed for HELCO and MECO, (ii) the specific projects and technologies, (iii) the estimated time and cost for any such projects, and (iv) to the extent it is not self-evident, a brief explanation of how the "infrastructure" is expected to enable or support additional distributed generation and transmission-interconnected renewable energy.

HECO Companies Response:

a. Please see the Hawaiian Electric Companies' Response to Commission Letter of February 19, 2010, filed February 26, 2010 in this Docket. In addition, the Conclusions and Recommendations sections of Attachments 2, 3, and 4 to Exhibit 1 describe issues and actions including areas for study. Some of the issues have been studied (as described in the document) and other issues require implementation or analysis. Where studies have been accomplished already, the results are reflected in the conclusions of these attachments.

b. The Attachments 2, 3, and 4 to Exhibit 1 and Table 8 of Exhibit 1 describe modifications that have been made or are ongoing on the HELCO and MECO systems to mitigate the effects of variable and distributed generation. Specific requirements for new infrastructure and the details of this implementation will be identified in the proposed

Reliability Standards Working Group, described in the Hawaiian Electric Companies' February 26, 2010 Response to Commission Letter of February 19, 2010.

BP-HECO-IR-12

Ref.: HECO RS Report

The HECO RS Report states that the HECO Companies support convening a "Reliability Standards Working Group." *Id.*, Exhibit I at 4.

a. Please discuss and explain the HECO Companies' proposals with regard to (i) whether the Public Utilities Commission ("Commission") or some other entity would convene and select the membership of the "Reliability Standards Working Group," (ii) whether the "Reliability Standards Working Group" would report to the Commission, (iii) whether and to what extent the "Reliability Standards Working Group" would operate outside of any docket or formal proceeding before the Commission, (iv) avenues for public participation in the "Reliability Standards Working Group," (v) the approximate date (month and year) the "Reliability Standards Working Group" would commence, (vi) whether and to what extent the "Reliability Standards Working Group" would issue formal and publicly-available reports and the estimated dates (month and year) of availability of any such reports, and (vii) estimated time (year) of disbandment of the "Reliability Standards Working Group" based upon completion of its essential tasks and objectives.

b. Please discuss and explain the HECO Companies' proposals with regard to potential interactions, regarding subject matter and participants, between any "Reliability Standards Working Group" and (i) the Hawaii Clean Energy Initiative working groups, (ii) the feed-in tariff docket (Docket No. 2008-0273), (ii) the integrated resources planning docket (Docket No. 2009-0108), (iii) the PV Host docket (Docket No. 2009-0098), and (iv) the Rule 14H docket (Docket No. 2010-0015).

<u>HECO Response:</u>

Please see the Hawaiian Electric Companies' Response to Commission Letter of February 19, 2010, filed February 26, 2010 in this proceeding.

BP-HECO-IR-13

Ref.: HECO RS Report

The HECO RS Report characterizes the HELCO system as having "high penetrations of distributed generation relative to overall system size." *Id.*, Exhibit 1 at 6. Rule 14H currently requires an interconnection study for distribution level circuits upon reaching 10% of distributed generation capacity, the HECO Companies have proposed raising this threshold from 10% to 15%, and the HECO RS Report indicates that existing variable and non-variable generation totals 4.7% and existing and planned variable and non-variable distributed generation total 8.8% of the HELCO system peak demand, which is below the 10% Rule 14H threshold. In light of these factors, please discuss and explain the HECO Companies' basis and rationale for the characterization of the HELCO system as having "high penetrations" of distributed generation.

HECO Companies Response:

To clarify, there have been two different type of peak loads discussed in the Feed-in-Tariff proceeding: system peak and circuit peak. A system peak is the maximum coincident load demand from all the loads on an island-wide system within a given timeframe. A circuit peak is the maximum load demand on a particular circuit within the system within a given timeframe.

The system peak cannot be determined by adding up all the individual circuit peaks on the system since the load on different circuits peak at different times. The system peak loads for the Hawaiian Electric Companies' islands typically occur on a weekday late in the year in the evening. The individual circuit peaks vary depending on what type of load is served by each circuit. For example, circuits in an industrial area tend to have their peak between 10am and 2pm, circuits in a residential area tend to peak in the evening between 6pm and 8pm, and circuits in a commercial area peak anywhere from as early as 4pm to 8pm. At the time of the system peak, the individual circuit could be at 40%, 75% or 90% of its circuit peak depending on what type of loads the circuit is serving. Therefore, the system peak load will be less than the sum of each individual circuit peaks.

The system peak and the circuit peaks provide the contexts against which generation penetration levels can be assessed. The issues that are assessed in relation to the circuit peaks are different from issues that are assessed in relation to the system peak. The issues related to circuit penetration levels are those issues that distributed generation can cause at the circuit level which include but are not limited to voltage regulation, transient voltage levels, and islanding risk. The issues related to system penetration levels are those issues that generation can cause at the system level which include but are not limited to frequency regulation, reserve requirements, transient stability, and excess energy. Since the issues related to circuit penetration and system penetration are different, the circuit penetration limits cannot be directly extrapolated to determine the system penetration limits.

HELCO is one of the first utilities in the United States and North America for which distributed PV generation is a significant contributor to the total MW production of the power system (see http://www.solarelectricpower.org/media/84522/sepa%20top%20ten%202009.pdf). The total distributed generation penetration of 4.7% of system peak on a system-wide level is considered high. The penetration level for a *system* that would be significant is a different valuation than the 10% distribution circuit level penetration study trigger in Rule 14.H which was designed to address interconnection concerns that occur when generation on a particular distribution *circuit* is large relative to demand on the circuit.

The 10% Rule 14.H threshold is a mechanism to ensure that an appropriate interconnection analysis can be conducted where the potential exists for the amount of distributed generation on a particular distribution circuit to be large relative to the load on the circuit. Where the proportion of distributed generation (in aggregate) in a circuit is large, relative to demand on the circuit, additional interconnection requirements can be necessary to protect the customers and generators on that circuit during situations such as distribution faults which can create an unintentional island. The interconnection study performed in association with distributed generation interconnection requests will look at the necessary infrastructure on the particular circuit, but does not study system-wide issues. Nor is there a trigger within Rule 14.H to trigger an examination of the system-wide impacts when the total system penetration of distributed generation becomes significant. Historically, the contribution of distributed resources to an overall power system has been small and therefore, the fact that these resources did not ride through faults, provided variable power, are not visible to the system operator, etc. did not cause system-level issues due to the relatively minor contribution from these resources. At the existing penetration level on the system, these issues are now causing system impacts and/or concerns as described in Attachments 2, 3 and 4.

Per Exhibit 1 of the Reliability Standards report, the existing penetration levels of DG on the system were presented as a percentage of the system peak (2009) respective to each of the islands. For Oahu, the 9,822 kW of variable DG resources equates to 0.82% on a system peak of 1200 MW. For the Big Island, the existing variable and non-variable DG resources (totaling 9,115.8 kW) equate to 4.7% of the total system peak of 194.6 MW. Accounting for existing and planned DG resources (17,066.6 kW), the percentage increases to 8.8% of the total system peak of 194.6 MW.

For the Rule 14.H threshold, Attachment 1 of Exhibit 1 is referenced and provides an example of the characteristics of distribution feeder circuits. In Attachment 1, BEW Engineering assessed two distribution feeder circuits on the Oahu system. As shown in the Figure 1 – Breaker A and Figure 2 – Breaker B, each circuit peak load differs depending on the time of day and the day of the week (actual system data from January 2010). Weekday peak loading of 3.48 MW (3.86 MVA) occurs between 9am and 10am while the weekend peak load for the same circuit is about 1.44 MW occurring around 4am to 5am and is almost 50% lower than the weekday peak. The Breaker B peak of 2.29 MW (2.4 MVA) extends from 8am to 5pm and has no night time peak. The typical Oahu evening system peak occurs at night from 7pm to 8pm, with the day time peak usually between noon and 2pm. As a result the, Breaker A and Breaker B peaks are non-coincident with the system peak. For Rule 14.H, the 10% or 15% ratings are calculated based on the 3.48 MW (Breaker A) and the 2.29 MW (Breaker B) measures for each of the feeder circuits. Based on Rule 14.H, 15% penetration would be reached if Breaker A had a project proposed at 522 kW (15% of 3.48 MW). For Breaker B, the limit would be a 343 kW (15% of 2.29 MW) customer system.

As part of BEW's analysis, an evaluation of the circuit minimums was also suggested as protection devices during low load conditions may not adequately protect the feeder if the DG generator exceeded the typical 3 to 1 load to generator ratio. Additional studies will need to be pursued for the highly loaded systems as well as those that exhibit characteristics like Breaker A.

BP-HECO-IR-14
Ref.: HECO RS Report
The HECO RS Report states, "As penetration levels of renewable resources continue to increase ... the conventional methodology for system balancing and frequency control through AGC employed on the Maui, Oahu and Hawaii island systems may no longer be feasible." *Id.*, Exhibit I at 10. For each of the Maui, Oahu, and Hawaii island systems, please (i) identify the quantity of renewable energy at which "the conventional methodology for system balancing and frequency control through AGC" may no longer be feasible, and (ii) explain the technical bases and reasons for the foregoing conclusion(s).

HECO Companies Response:

This should be clarified to be in reference to *variable* renewable energy. As penetration levels of *variable* renewable energy continue to increase the conventional methodology for system balancing and frequency control through AGC may not be feasible. The specific quantity of renewable energy at which the conventional methodology for system balancing and frequency control through AGC may no longer be feasible will be determined by the level of fast time-scale variations in overall system balance (which are reflected in the system as fast-time scale variations in frequency). Such variations cannot be managed through supplemental AGC frequency regulation due to the time delay inherent in the AGC control cycle. The amount of variable renewable generation at which point this would occur is dependent upon, but not limited to, various factors that include the system frequency response and , the characteristics of future renewable generation (in particular, the degree of volatility). The basis for the difficulty in specifying a quantity of renewable energy is mainly due to being unable to foresee changes in technology and the types of non-utility renewable generation interconnecting to the system. If a renewable generation facility operates and responds as a conventional generating unit on AGC, the system will be able to accommodate a greater amount of renewable generation while still being able to control system balancing and frequency control through AGC.

<u>BP-HECO-IR-15</u>

Ref.: HECO RS Report

The HECO RS Report refers to observations of HELCO Operations personnel that load-shedding is occurring for losses of generation that previously did not result in under frequency load-shed. Id., Exhibit I at 16.

a. Please identify all occurrences of under frequency load shedding ("UFLS") on the HELCO system from January 1, 2008 through the present, including (i) the date of the disturbance (i.e., loss of generation unit), (ii) the system frequency level prior to the disturbance, (iii) the frequency nadir (i.e., lowest frequency excursion), (iv) the frequency level(s) at which the UFLS occurred, (v) quantity of load shed in MWs, (vi) duration of the load shed, and (vii) a brief description of the precipitating generation system disturbance event.
b. Please discuss and explain the effect, if any, of HELCO system UFLS on reliability-related records or statistics concerning System Average Interruption Frequency Index ("SAIFI") and/or System Average Interruption Duration Index ("SAIDI") for the HELCO system.
c. Please provide the various UFLS frequency trip points and associated MWs of target load shed for each UFLS block for the HECO, HELCO and MECO systems.
d. Please discuss and explain whether and to what extent changes in frequency trip settings for distributed generation projects on the HELCO system may impact UFLS.
e. Please provide tables for HECO and MECO equivalent to table titled "HELCO System Frequency Targets and Action Levels" on page 3 of Attachment 3 to the HECO RS Report.

<u>HECO Companies Response:</u>

a. For HELCO, please see Attachment A. The system frequency level prior to the disturbance and the frequency nadir are not available. The frequency level at which the UFLS occurred is determined by the block(s) shed (see response to subpart c). The actual amount of MW shed is not shown. The load shed indicated represents the value at peak demand for the circuits in the block; rather than actual demand at the time of the event. Actual demand at the time of the event is not readily available. The duration is based on the longest outage duration of any of the circuits shed. A change in underfrequency load shed (UFLS) scheme was implemented in 2009 as described in the response to subpart c.

b. The SAIF is a measure of the number of outages a customer experiences will increase with underfrequency load shed events. The SAIDI represents the average duration of outages. The impact of UFLS events on SAIDI depends on the typical duration of these outages. In general for the HELCO system, UFLS outages are of short duration due to available fast-start capacity which can come online to allow the restoration of customers and so tends to reduce the SAID. However at times, the duration can be longer due to problems with the remote close or insufficient standby generation so this is not always true.

c. For the Big Island, the current UFLS is shown below.

Load Shed Block No.	**Load Shed Peak MW**	**TRIP SETTING (Hz)**
Kicker Block	4.12*	59.3, 1181 cycle delay
1	14.46	58.8
2	17.41	58.5
3	35.71*	58.0
4	30.64*	57.7
5, Kicker Block	4.12*	58.0, 3 cycle delay

* Estimated MW only, additional circuit added MW not included in total MW

For the Maui, the UFLS is shown below.

Load Shed Block No.	**Load Shed Peak MW**	**Load Shed Min. MW**	**TRIP SETTING (Hz)**
1	1.00	1.00	59.3
2	9.21	5.39	58.7
3	15.05	7.95	58.5
4	12.03	4.54	58.0

For the Oahu grid, the UFLS based on the new proposed scheme is shown below.

Load Shed Block No.	Load Shed (MW)	TRIP SETTING (Hz)
Kicker 1	25	59.0, 5 sec delay
Kicker 2	25	59.0, 10 sec delay
1	46	58.9
2	47	58.7
3	92	58.4
4	105	58.1
5	105	57.8

d. The impact of distributed generation trip settings on the UFLS scheme (and under voltage load shed scheme) was identified for further study in Attachment 2. It is found that nuisance tripping of DG at present levels on the HELCO system is contributing to either a lower frequency nadir and/or additional load shed during low-frequency as confirmed by the recently completed study discussed in Attachment 2. It would be prudent to build on the study to examine the effect of undervoltage tripping (during faults), identify the best ride-through settings for DG, and confirm the response of the DG in field trials with modified settings, and confirm that the existing scheme is sufficient to protect the system for the known settings and amounts of DG.

e.

Maui System Frequency Targets and Action Levels

60.20 Hz	High Frequency Emergency Alarm level: Operator to take corrective action
60.05 - 59.95 Hz	Targeted frequency control range
59.8 - 59.5 Hz	Under Frequency Alarm level: Operator to monitor and take corrective action

59.5 - 59.3 Hz	Under Frequency Emergency Alarm level: Operator to take corrective action including manual load shedding
59.3 Hz	Instantaneous under frequency load shedding of block #1
58.7 Hz	Instantaneous under frequency load shedding of block #2
58.5 Hz	Instantaneous under frequency load shedding of block #3
58.0 Hz	Instantaneous under frequency load shedding of block #4

Modifications to the underfrequency load scheme for the Oahu grid to improve overall system reliability and reduce impacts to customers are nearly complete. The table below reflects the frequency targets and action levels for Oahu with the new proposed UFLS blocks shown in italics.

Oahu System Frequency Targets and Action Levels

66 Hz - 61.5 Hz	Generator unit overspeed protection limits and trips active
60.05 - 59.95 Hz	Targeted frequency control range
59.8 - 59.5 Hz	Under Frequency Alarm level: Operator to monitor and take corrective action
59.5 - 59.3 Hz	Under Frequency Emergency Alarm level: Generators switch from EMS control to local frequency control (LFC)
59 Hz	*Kicker 1 Block triggered with 5 sec delay*
59 Hz	*Kicker 2 Block triggered with 10 sec delay*
58.9 Hz	*Instantaneous under frequency load shedding of block #1*
58.7 Hz	*Instantaneous under frequency load shedding of block #2*
58.4 Hz	*Instantaneous under frequency load shedding of block #3*
58.1 Hz	*Instantaneous under frequency load shedding of block #4*

57.8 Hz	*Instantaneous under frequency load shedding of block #5*

Date	Description/Cause of Event	UF Block(s) Shed (Partial indicates not all circuits on the block opened)	System Load (MW)	Load Shed (MW)	Duration (minutes)
1/7/2008	Loss of Hill 6 @ 20.0 NW	1, 2 (partial)	169.8	9.5	5
4/24/2008	Loss of Hill 6 @ 20.4 NW	1	164.8	9.9	6
4/29/2008	Loss of Hill 6@20.3 MW	1 (partial)	121.9	6.1	4
5/19/2008	Loss of CT4 @ 13.6 MW	1 (partial)	121.9	6.1	4
6/23/2008	*Loss of HEP CT2, net loss 29.5 MW*	*1*	*162.5*	*6.6*	*36*
7/2/2008	Loss of HEP CT1, net loss 29.6 MW	1, 2	162.5	18.4	7
7/31/2008	Loss of Hill 6@20.6 MW	1, 2	171.9	16.6	48
8/1/2008	Loss of Hill 6 @ 20.5 MW	1, 2	165.1	16.5	5
8/30/2008	Loss of Puna Steam @ 10.8	1	98.1	4.6	14
9/11/2008	Loss of Hill 6 @18.4 MW	1	163.3	8.2	2
10/15/2008	18 MW Rampdown on CT4	1	159.5	9.1	4
2/5/2009	Loss of Hill 6 @ 18.6 MW	1	95.1	4.4	4
3/18/2009	Lightening caused loss of Hill 6, Hill 5, and Puna Steam; total 47.8 MW	1, 2 (partial)	153.2	11.1	31
3/20/2009	Loss of Pakini Nui Wind plant @15.93 MW	1	152.57	7.14	10
3/25/2009	Change in U.F. Scheme, block 1 @58.8 Hz, add block 5 (time delay@59.3 Hz)				
5/21/2009	Loss of Puna CT-3 @ 12.0 mw	1	160.86	14	3
6/22/2009	Loss of Keahole ST-7@11 MW	5	160.4	5.7	34
6/25/2009	Loss of 3300 line/HRD wind plant net 6.8 MW	1	159.9	14	4
7/8/2009	Loss of CT4 in CC, net 15.5 MW	1	169.4	13.9	4
7/14/2009	Loss of CT4 @ 17.8 MW	1	164.8	12.2	7
7/22/2009	Loss of Puna @14.0 MW	1	169.2	9.4	4
8/13/2009	Loss of CT5@18.4 MW	1	173.7	17.3	6
9/22/2009	Loss of ST7@12.6 MW	1	169.1	21.4	34
9/23/2009	Loss of CT3 @20.4 MW	5	180.1	7.4	4
10/14/2009	Loss of HEP @20.7 MW	1	166.1	17.8	7
10/20/2009	Loss of ST-7 @12.5 MW	5	173.2	6.3	7
10/23/2009	Loss of ST7@12.4 MW	1	164.5	14.7	4
11/18/2009	Apollo Wind Farm ramp down 14 MW	5	173.2	6.3	4
11/29/2009	Loss of Hill 6@20.3 MW	5	148.2	5.1	11
11/30/3009	Loss of CT5 in CC; total loss 24 MW	1	180.45	17.7	8
1/23/2010	Loss of Puna@13.5 MW	5	124.5	3.56	4
1/26/2010	Loss of Puna@13.3 MW	1	172.7	20.7	8

BP-HECO-IR-16
Ref.: HECO RS Report
Please discuss and explain whether and to what extent a requirement that all new distributed generation projects on the HELCO system have expanded under-frequency and under-voltage ride-through capabilities, consistent with the HECO Companies' proposed modifications to Tariff Rule 14H, would prevent or reduce increases in the quantity of UFLS "nuisance trips," and amount of load associated with each such "nuisance trip," assuming additional distributed generation is connected to the HELCO system and all other system design and operation practices remain unchanged.

HECO Companies Response:

Nuisance trip is a term which is meant to describe loss of DG for transmission disturbances. The trips are caused by settings intended to disconnect the DG for a problem on the distribution circuit to which it is connected, but instead result in mis-tripping for a transmission disturbance which did not require the DG to disconnect. It is assumed that expanded ride-through as reflected in the proposed Rule 14.H modification will reduce the number of nuisance trips due to system disturbances and this will be a positive measure to mitigate problems on the system for high penetration of distributed generation. Trips due to frequency will occur for all DG in the aggregate as frequency is a system-wide event; so the amount of DG lost will be determined by the settings on the DG throughout the system. The amount of DG lost for under voltage conditions will be within the portion of the system affected by the fault, as voltage impacts are localized on the system. The tripping due to under-voltage needs to be assessed through simulation of fault conditions on the HELCO system, so an appropriate ride-through requirement can be developed to avoid wide-spread loss due to faults. Underfrequency tripping was of greatest concern due to it being a system-wide parameter; but under-voltage tripping is another concern as described in Attachment 2. As discussed in the response to BP-HECO-IR-15 item d; the impact of nuisance trips on the under voltage and underfrequency load-shed schemes, and establishing an appropriate ride-through requirement to mitigate these impacts, is an area that requires analysis. In addition it is also important to verify the performance of the equipment with the expanded ride-through settings in the field as expanded settings differ from typical installations in North American systems and so may not be as proven.

BP-HECO-IR-17
Ref.: HECO RS Report
The HECO RS Report indicates that the amount of currently installed DG for HECO includes 30 MWs of dispatchable distributed generation (peakers) which would not factor into the consideration for additional DG. Please discuss and explain whether there are any equivalent types of dispatchable distributed generation concerning the HELCO and MECO systems.

HECO Companies Response:

MECO has two 1,000kW dispatchable diesel generators located in the Hana Substation in East Maui at the end of a radial 23kV transmission line. The distributed generation located in the Hana Substation primarily serve as emergency generators for the Hana community during outages on the radial 23kV transmission line.

HELCO has four dispersed diesel generators located at four remote distribution stations with remote start/stop capability, coming online to full output (1 MW) in 30 seconds. These units are used for emergency system balancing (offline fast-start supplemental reserves) and restoration of system frequency following disturbances. In addition to remote monitoring and control capability through the SCADA/EMS system, the four dispersed units have special protection schemes to trip them offline and lock them out should the distribution circuit to which they are connected open.

These units were not included in the DG totals for MECO or HELCO in Exhibit 1 or the Attachments. They are considered as dispatchable units.

BP-HECO-IR-18

Ref.: HECO RS Report

The HECO RS report refers to curtailment of excess energy. *See, e.g., id.,* Exhibit 1 at 19. Please provide, for HECO, HELCO and MECO grids, the actual and/or estimated total amount of curtailed energy, in aggregate and expressed in megawatt hours ("MWh"), by month and by on-peak (day) and off-peak (night) periods, for the period of January 1, 2008 to the present.

HECO Companies Response:

The Hawaiian Electric Companies (MECO, HELCO and HECO grids) do not collect actual or estimated curtailed energy data from the as-available renewable generation facilities as current data monitoring only captures energy produced (kWh). MECO, HELCO, and HECO have limited real-time generation information through SCADA from existing as-available renewable generation facilities. The data provided is generally limited to that specified in the purchase power agreement and there are additional competitive sensitivities amongst PPAs in sharing that information. Estimating curtailments would require real-time monitoring of the source energy, an energy conversion model for the source energy (i.e.; wind or solar available at each generating source), resource forecasting and equipment availability information for each of the energy producing components (i.e.; turbine availability for wind plants, hydro facilities, etc) which currently does not exist on any of the systems. None of the non-utility renewable generation facilities connected to the MECO or HELCO systems provide estimated possible production or historical curtailed energy data. The limited information provided by the producers on equipment status, raw energy source and power conversion, as well as the change in the variable potential energy source during curtailments, makes it infeasible for MECO or HELCO to estimate the amount of curtailed energy. The analysis is further complicated where there are multiple variable energy providers in the curtailment queue, as is the case at HELCO.

The Hawaiian Electric Companies are also actively investigating wind resource monitoring and forecasting tools to improve applicability of those tools for the islands and as part of the initiatives to integrate more renewable resources to meet RPS. Under the Hawaiian Utility Integration (H.U.I) initiative funded by ARRA stimulus funding, the Companies have teamed with leading wind forecasting providers, utilities in California and Oregon and the CaISO, UH and national laboratories to launch the WindNET ramp event and wind forecasting development effort. As these collaborative efforts continue, tools will be developed to enable the Companies to better manage the as-available resources.

BP-HECO-IR-19
Ref.: HECO RS Report
The HECO RS report refers to "planned" distributed generation projects for the HELCO and MECO systems. *Id.*, Exhibit 1 at 15, 25.

a. Please discuss and explain (i) whether and to what extent the HECO RS Report is based on the assumption that any such "planned" distributed generation projects will be in commercial operation during the time period of2010 to 2012, and (ii) the effect on the discussion and analysis in the HECO RS Report concerning reliability standards if any or all such projects are not in commercial operation during the time period of201 0 through 2012.
b. Please discuss and explain, for the HECO, HELCO and MECO systems, the specific criteria (e.g., executed or Commission-approved power purchase agreement, request for interconnection, etc.) used by the HECO Companies to determine whether a project is a "planned" distribution or transmission generation project as that term is used in the HECO RS Report.
c. Please discuss and explain the rationale and basis for including projects referred to as "Proposed PPA" in Table 4 of Exhibit 1, concerning MECO reliability standards, insofar as the HECO RS Report states that "MECO ... plans to defer entering into bi-lateral PPA negotiations with the projects shown [in Table 4] as 'Proposed PPA.[.]'" *Id.*, Exhibit 1 at 25.
d. Please discuss and explain whether and to what extent the HECO RS Report assumed the "Wind 2" and "Wind 3" projects on Maui, identified in the HECO RS Report, (i) will or will not incorporate on-site storage technologies for the purpose of mitigating wind generation output variability, and (ii) the extent to which incorporation of on-site storage technologies will or will not affect the reliability standards proposed in the HECO RS Report.

<u>HECO Companies Response:</u>

a. The discussions of excess energy contained within the HECO RS report are not dependent on the assumption that the "planned" distributed generation projects shown on pages 15 and 25 of Exhibit 1 will be in commercial operation between 2010 and 2012. Should the "planned" distribution projects not be in commercial operation by 2012, the discussion and analysis would still hold. For HELCO and MECO, existing resources are already exhibiting impacts resulting in curtailment. Addition of more as-available "planned" resources may exacerbate the current observed system excess energy issues, until impact studies are completed and mitigation technologies and strategies are implemented. Analysis summarized in Attachment 4 primarily compared 2008 and 2009 data. Figure 7 of Attachment 4 also showed the load curves over a 24 hour period with additional "Planned" distributed generation on MECO The figure is illustrative of the fact that existing excess energy issues already exist today especially during the low-load night time hours with wind. Addition of new as-available resources exacerbates the integration challenge by increasing the complexity of the excess energy issue.

b. The "planned" projects on pages 15 and 25 of Exhibit 1 contain only distributed generation projects; no transmission generation projects are included. The "planned" projects are distributed generation projects that have submitted documentation to the HECO Utilities and have initiated interconnection review of their projects.

c. The rationale behind including "proposed PPA" projects in Table 4 was to indicate the desire of developers to connect additional distributed generation, including variable resources to the Maui grid.

d. From the excess energy perspective, the HECO RS Report, in particular Attachment 4, made no assumptions as to any on-site storage technologies that may or may not be incorporated into the Wind 2 and Wind 3 projects. The analysis in Attachment 4 looks at excess energy issues, on which the on-site storage technologies being considered at these wind farms for the "purpose of mitigating wind generation output variability" would have little, if any, effect. The extent to which incorporation of on-site storage technologies will affect the recommendations of the reliability standards contained within the HECO RS Report would depend on the size (MW and MWh), characteristics, and intended function of the on-site storage technologies being considered.

BP-HECO-IR-20
Ref.: HECO RS Report
Table 8 of Exhibit 1 to the HECO RS Report states that it identifies and discusses current "system operating criteria" and various "operating action[s] or rule[s]" for the HECO, HELCO and MECO systems. Please produce electronic and/or hard copies of all formal written operating procedures and/or practices concerning such system operating criteria and operating actions and rules. If any document(s) are not produced, please provide a detailed explanation concerning the basis for not producing such document(s).

HECO Companies Response:

Documents are not being provided in this response, as the criteria described in the matrix collects key requirements and practices or measures pertaining to reliability from an extensive and diverse range of sources, including planning criteria, operational criteria and practices, parameter settings on the real-time operations systems (SCADA/EMS and AGC), recorded system frequency performance, etc. and not from an easily producible set of published procedures. It is for this reason that one of the key objectives for the reliability filing was to pull together the information from the various sources for the three Companies into the consolidated matrix.

<u>BP-HECO-IR-21</u>
Ref.: HECO RS Report
Please discuss and explain whether and to what extent the reliability standards contained in the HECO RS Report may limit or otherwise affect FIT Tier 3 projects.

<u>HECO Companies Response:</u>

The reliability standards contained in the HECO RS Report were based on issues and constraints for variable and/or distributed generation resources. The issues pertaining to the acceptance of variable and distributed generation resources identified in the report apply to all projects involving variable and/or distributed generation, including FIT Tier 3 projects.

Please see the Hawaiian Electric Companies' February 26, 2010 filing to the Commission. As discussed in that filing, the Hawaiian Electric Companies believe that FIT, including Tier 3, can be fully implemented on Oahu per the September 25, 2009 Decision and Order in this proceeding. Hover, the timing and scope of implementation of FIT at MECO and HELCO should be subject to review by the proposed Reliability Standards Working Group.

BP-HECO-IR-22
Ref.: HECO RS Report
Please discuss and explain whether and to what extent the HECO Companies anticipate modifying their ancillary services practices, as described in Attachment 3 to Exhibit I of the HECO RS Report, in a manner that is likely to increase the accommodation of intermittent renewable resources, if the Commission adopts the HECO Companies' proposal in the decoupling docket (Docket No. 2008-0274) concerning the Energy Cost Adjustment Clause ("ECAC") heat rate incentive mechanism.

HECO Companies Response:

It is not clear what is meant by "ancillary services" practices as there is not such a policy described in Attachment 3. Attachment 3 describes the mechanisms responsible for system balancing and frequency control. Aspects of system frequency and control, such as primary frequency response by generating units, are not considered ancillary services. If the question pertains specifically to reserve policies; no changes to operational practices for system balancing and control – including changes to reserve policies – are anticipated due to any changes in cost recovery mechanisms (such as ECAC and/or decoupling).

BP-HECO-IR-23

Ref.: HECO RS Report

The HECO RS Report states, "The HELCO system has individual circuits with up to 62% penetration of distributed generation." !d., Exhibit I at 15. Please discuss and explain in detail, on an individual circuit basis, any and all technical modifications to HECO, HELCO and/or MECO system circuits with similarly high penetrations of distributed generation.

HECO Companies Response:

MECO has only one circuit with a similarly high penetration (60+%) of distributed generation. Circuit 1210 on Lanai has a high penetration of renewable distributed generation with both the La Ola PV facility (LSR) and the Manele Bay combined heat and power (CHP) unit on the circuit, and the DG penetration is expected to increase as the La Ola PV facility increases production. The La Ola PV facility is not a typical DG installation. LSR and MECO have invested a considerable amount of time and capital funds in interconnecting the PV farm. A detailed interconnection requirement study was performed for the La Ola PV Farm and, as a result, the facility has the following attributes (among others):

- Three-way direct trip transfer protection scheme with a dedicated fiber optic communication system
- SCADA monitoring of multiple analog, status and control points at 2 second scan rate
- Remote curtailment capabilities at both the Miki Basin Power Plant and the Maui Operations Dispatch Center
- Specific performance and reporting requirements defined in a power purchase agreement and monitored for compliance

For an example of the technical modifications made to a HELCO circuit with a high penetration of DG, please see the Companies response to SA/HSEA-RS-IR-15 item (b) regarding analysis done for the Host Park 11 circuit.

It is important to note that these examples illustrate technical modifications that are not typical for FIT projects, and due to costs associated with performing the interconnection analysis, identifying the necessary interconnection requirements, and implementing these projects, should not be considered as a standard typical project. However, it does show that with detailed studies, site specific modifications can be done, but it does come at a significant cost that would be beyond the intended scope of a FIT program.

HECO currently does not have penetration levels at the 60% level. Individual project Interconnection studies currently follow Rule 14H Interconnection requirements. As more distribute generation resources come online, more project specific and interconnection studies are expected and aggregated system Level-1 impact studies are being proposed to proactively gauge potential impacts on the Oahu system as part of the FIT Reliability Standards Filing, Exhibit 1.

BP-HECO-IR-24

Ref.: HECO RS Report

Please discuss whether and to what extent studies concerning "excess energy," as that term is used in the HECO RS Report, on the HELCO and MECO systems rely upon data that includes only renewable energy from (i) the addition of FIT Tiers 1 and 2 projects equal to 5% of HELCO and MECO 2008 system peak load, (ii) all existing and planned transmission, and sub-transmission renewable energy projects, or (iii) all existing and planned transmission sub-transmission, and distribution renewable energy projects.

HECO Companies Response:

The studies concerning "excess energy" on the HELCO and MECO systems do not include any planned distribution system level renewable energy projects nor do they include renewable energy from the addition of FIT Tiers 1 and 2 projects equal to 5% of MECO or HELCO's 2008 system peak load. The loads used for the analysis are based on recorded 2008/2009 system demand. The studies concerning "excess energy" on the MECO system use data that includes all existing transmission renewable energy projects, two planned wind farms, all existing distribution renewable energy projects (as reflected in the recorded 2008/2009 load curves) and no planned distribution renewable energy projects. The studies concerning "excess energy" on the HELCO system use data that includes all existing and planned transmission renewable energy projects, all existing distribution renewable energy projects (as reflected in the recorded 2008/2009 load curves) and no planned distribution renewable energy projects.

BP-HECO-IR-25

Ref.: HECO RS Report

With regard to curtailment for excess energy:

a. Please provide in electronic format the underlying data for system load duration curves for the HECO, HELCO, and MECO systems for 2008 and 2009, including hourly system load data with the date and time for each hourly load. If any document(s) are not produced, please provide a detailed explanation concerning the basis for not producing such document(s).

b. For all variable renewable energy generation resources subject to curtailment by the HECO Companies due to excess energy, please provide in electronic format the hourly aggregate generation output for the time period of January 1, 2008 through December 31, 2009. If any document(s) are not produced, please provide a detailed explanation concerning the basis for not producing such document(s).

HECO Companies Response:

a. See file "Dkt 2008-0273 BP-HECO-25 MECO SysLoad_2008-2009.xls" for hourly MECO system loads. See file "Dkt 2008-0273 BP-HECO-25_HELCO Sysload_2008-2009. xls for hourly HELCO system loads. See file "Dkt 2008-0273 BP-HECO-25 HECO_Hourly Load Data 2008 and 2009.

b. See file "Dkt 2008-0273 BP-HECO-25 KWP_MW 2008-2009.xls" for the hourly Kaheawa Wind Farm aggregate generation output. See file "Dkt 2008-0273 BP-HECO-25 Makila 2008-2009" for the hourly Makila Hydro generation. (Note - Makila Hydro only operated in the last 2 months of 2009. Also, as Makila Hydro is a DG unit, its generation is already accounted for as a load reduction in the system load data included as part of a.) See file "Dkt 2008-0273 BP-HECO-25 LanaiPV_KW_2009.xls" for the hourly La Ola PV facility on Lanai aggregate generation output. Hourly generation output data for the La Ola PV facility not available for the full time period requested. SCADA for the La Ola facility came online in January 2009 and was off-line from August 25, 2009 to October 8, 2009 due to work being done for the Manele CHP. See file "Dkt 2008-0273 BP-HECO-25 HELCO Variable 2008-2009.xls" for hourly HELCO variable generation. This file does not contain hourly generation data for non-telemetered sources (such as distributed generation, not monitored on the SCADA/EMS) as such data is not available. A portion of the geothermal export during off-peak hours is treated as must-take energy in the curtailment priority, but is not variable and therefore is not included in the summary. HECO currently does not have any large-scale wind or solar generators on island to collect such excess energy curtailment data from.

BP-HECO-IR-26
Ref.: HECO RS Report
The HECO RS Report refers to "regulating reserves" for HELCO and MECO.
See, e.g., id., Attachment 3 to Exhibit 1 at 8; Attachment 4 to Exhibit 1 at 9. Please discuss and explain whether and to what extent any differences between HELCO and MECO in terms of operating practices account for differences between HELCO and MECO in terms of regulating reserves. Please also briefly describe HECO's anticipated operating practice concerning regulating reserves for the anticipated Kahuku Wind Power project.

HECO Companies Response:

The general purpose of regulating reserves is the same for both MECO and HELCO, however, there are significant differences between the utilities that affect the amount of regulating reserves each utility carries. In addition, the amount of reserves necessary for each Company will be dependent upon the conditions on the particular day. Regulating reserves are those reserves immediately responsive to AGC control, which are used for supplemental frequency control and load following in the near term. What constitutes the near term will depend on factors such as the startup time for the next unit in the dispatch queue. In considering the amount of reserves, the observed variability of the system is taken into account as well as the uncertainties in the load and variable generation forecast. The amount of regulating reserve MECO carries differs from HELCO's regulating reserve amounts due to the differences in the mix of firm generation, the differences in the ability of firm generation to respond to frequency errors, the differences in availability and characteristics of as-available generation, and the differences in transmission systems (which affects the potential loss of load for determining reserve down requirements). Under conditions of large amounts of must-take variable energy, regulating reserves up increase not only due to the need for responsive generation, but also due to the fact that must-run dispatchable units will often operate at part-load to accommodate the variable resources.

Maintaining the required amount of reserves down requires operator intervention by taking units offline or implementing curtailments, as appropriate.

With respect to HECO's anticipated operating practice concerning regulating reserves for the anticipated Kahuku Wind Power project, HECO has not made a determination yet as to whether it will carry additional regulating reserve to accommodate the 30 MW Kahuku Wind Power project and, if so, how much additional regulating reserve it will carry.

<u>BP-HECO-IR-27</u>
Ref.: HECO RS Report
Please discuss and explain whether and to what extent the reliability standards contained in the HECO RS Report comply with the statement in the Feed-in Tariff D&0 that "FIT generation should displace fossil fuel generation." Feed-in Tariff D&O at 51.

<u>HECO Companies Response:</u>

The complete quotation and context of the quoted text is set forth at pages 50-51 of the Decision and Order as follows:

The commission in particular wants the HECO Companies to adopt standards that establish when additional renewable energy can or cannot be added on an island or region therein <u>without markedly increasing curtailment, either for existing or new renewable projects</u>. FIT generation should meet new load requirements and displace fossil fuel generation. Accordingly, <u>FIT projects should not meaningfully displace existing renewable energy generation</u>. For instance, minimum load standards could demonstrate whether additional wind generation could be added to the HELCO and MECO grids <u>without harming reliability or directly leading to more curtailment of existing renewables during off-peak hours</u>.

(Emphasis supplied)

Accordingly, the Commission's discussion is directed at ensuring that FIT resources are to the extent possible meeting new load requirements and displacing the need for fossil fuel generation, rather than increasing curtailment for existing or new renewable projects. As discussed in the Hawaiian Electric Companies' Report on Reliability Standards filed on February 8, 2010, the Companies' reliability standards comply with the foregoing discussion because they were based upon system studies to determine the extent to which FIT resources could be accommodated on each island without compromising system reliability or causing significant curtailment of new or existing renewable energy generators.

BP-HECO-IR-28
Ref.: HECO RS Report
The HECO RS Report states that "steady-state excess energy (curtailment) impacts and dynamic system frequency issues are proposed as initial measures" for the reliability standards discussed in the report. *Id.*, Exhibit 1 at 9. Please describe the specific measures utilized to evaluate and analyze alleged excess energy and dynamic system frequency, including specific targets, study methodologies, modeling analyses, technology assumptions, use of a system dispatch models, etc. Please also provide copies of all analyses and model results concerning the foregoing.

HECO Companies Response:

The analysis for excess energy issues is provided within Attachment 4 of the Companies Reliability Standards, "Evaluation of Excess Energy and Curtailment". The analysis considered potential curtailments on the basis of two methods. One is a comparison of a 24-hour load demand curve today, compared with maximum potential renewable energy resource production (existing and planned), and the minimum must-run generation (with consideration of reserves). This method gives an idea of the potential number of MW of curtailment during a particular 24 hour period. The other method examined the possible hours of curtailment based on load duration curve. This method evaluated curtailment hours compared to a similar assumption (maximum RE) as in the stack charts, and also against average variable and maximum dispatchable RE, again for both existing and planned RE conditions.

Assessments of the existing system frequency and dynamic stability issues and impacts from the types of generation eligible for FIT are described in Attachments 2, Evaluation of Distributed Generation, and 3, Evaluation of System Balancing and Frequency Control. These evaluations describe measured impacts and analysis in detail especially for the HELCO system, which presently has experienced a significant impact on system frequency on both steady state and dynamic time scales from the existing variable and distributed generation resources. This includes greal-time data of system frequency impacts from variable generation sources in Attachment 3, and graphs illustrating the modeled impact from aggregate loss of PV on the system dynamic frequency response to generator contingencies in Attachment 2.

Particular studies, if they have been completed, are cited within the attachments. System frequency is a parameter monitored in real-time and the criteria and action levels are contained in Table 8 of Exhibit 1.

BP-HECO-IR-29

Ref.: HECO RS Report

Please provide a list describing all existing and planned energy storage technologies or resources, including but not limited to battery systems, including the island grid location, charging and discharging rate, and MW and MWh capacity of such storage systems. Please also provide a list of all distributed generation resources added in 2008 and added in 2009, expressed in aggregate total MW and differentiated by technology (i.e., solar PV, wind, geothermal, etc.).

HECO Companies Response:

The Hawaiian Electric Companies are aware of five planned battery energy storage systems (BESS) within its service territories, excluding back-up battery systems located at customer sites. These include planned BESS projects at two proposed wind farms and one planned distributed generation PV project on Maui, one planned BESS at an existing PV project on Lanai, and a planned BESS at a proposed wind farm on Oahu. The independent power producers of the proposed wind farms and existing PV system are working to develop BESS projects that will meet performance requirements and grid reliability needs. Select specifications of the BESS are specified in filed power purchase agreements (PPAs); however, some specifications and performance requirements are either not publicly available or undetermined at this time subject to further design/engineering or PPA negotiations.

Estimates of distributed generation (DG)[1] added in 2008 and 2009 within the Companies' service territories, in MW by technology, is provided below.

[1] As stated in Hawaiian Electric Companies' Preliminary Statement of Position, Exhibit A of Docket No. 03-0371 (Instituting a Proceeding to Investigate Distributed Generation in Hawaii) filed on May 7, 2004, "As defined by the Commission in this Docket, distributed generation involves the use of small scale electric generating technologies installed at, or in close proximity to, the end-user's location. The Companies have not attempted to define "small"

	DG Added in 2008, MW					
	Oahu	Big Island	Maui	Molokai	Lanai	Total
Photovoltaics	4.7	1.3	0.81	0.14	0.25	7.2
Wind	0	0.03	0.004	0	0	0.03
Combined Heat and Power	0	0	0	0	0	0
Total	4.7	1.3	0.81	0.14	0.25	7.2

	DG Added in 2009, MW					
	Oahu	Big Island	Maui	Molokai	Lanai	Total
Photovoltaics	5.7	2.8	2.8	0.06	0.36	11.7
Wind	0	0.037	0.007	0	0	0.04
Combined Heat and Power	0	0	0.45	0	0.83	1.3
Total	5.7	2.9	3.2	0.06	1.2	13.0

for purposes of this proceeding, but note that "small" should be construed relative to the utility's system loads, and to the loads of large customers."

BP-HECO-IR-30

Ref.: HECO RS Report

Please (i) provide a list identifying the title and subject matter, author(s), and date of all formal reports, studies, proposals and similar documents identified in the HECO RS Report and in the possession or control of the HECO Companies, and (ii) produce electronic and/or hard copies of all such reports, studies, proposals and similar documents. If any document(s) are not produced, please provide a detailed explanation concerning the basis for not producing such document(s).

HECO Companies Response:

The Majority of the relevant documents identified in the HECO RS Report were attached to the Reliability Standard Docket filing. The Company requests discretionary privilege as some internal company reports reference specific customer projects by name citing system issues. Some sensitive customer loads may also co-exist on circuits undergoing interconnection studies. The Company recommends not distributing due to competitive nature of various parties with similar technologies participating in these proceeding.

- Attachment 1, 5, and 6 were conducted by BEW Engineering staff, completed for the February 2010 filing.
- Attachment 2, 3, and are based on internal Hawaiian Electric Company staff analysis of the operating system data, distribution data and project data.
- Various references were made throughout Exhibit 1. Document access information (hardcopies, web links or bibliography references) are provided for parties to locate documents. Note formal membership to organizations such as EPRI may be required to access referenced reports. The Companies will not provide

Title	Access/Availability
1. Electric Power Systems Inc., *Hawaiian Electric Light Company Wind Generation Impact Study – Phase II,* December 29, 2006 (provided May 8, 2009)	Company internal report, Provided earlier as supplemental information in earlier FIT submission, May 8, 2009
2. Electric Power Systems Inc., *HELCO Maximum Penetration of Distributed Generation Study,* August 2009	Company internal report, See attached Exhibit 1.
3. L. Dangelmaier and D. Brooks (EPRI), "HELCO Wind AGC Impact Analyses",	Highlights from EPRI report 1018716, See attached Exhibit 2.

UWIG Spring Meeting, Fort Worth, TX, April 17, 2008	
4. EPRI, Evaluation of the Effectiveness of AGC Alterations for Improved Control with Significant Wind Generation, EPRI Report 1018715, Palo Alto, CA 2007	EPRI Program Member report
5. EPRI, *Evaluation of the Impacts of Wind Generation on HELCO AGC and System Performance Phase 2*, EPRI Report 1018716, Palo Alto, CA 2009	EPRI Program Member report
6. S. Fink, C. Mudd, K. Porter and B. Morgenstem, *Wind Energy Curtailment Case Studies*, NREL/SR-550-46716, October 2009	NREL website www.nrel.gov/docs/fy10osti/46716.pdf
7. California Energy Commission, *Intermittency Analysis Project*, CEC-500-2007-081, 2007 8. *Interstate Generation and Delivery into California from the Western Energy Coordinating Council States*, CEC-500-2005-D64D, April 2005 9. *Strategic Value Analysis for Integrating Renewable Technologies in Meeting Target Renewable Penetrations*, CEC-500-2005-081, 2005	CEC website, www.energy.ca.gov
10. C. Hubert, *Electric Machines: Theory, Operation, Application, Adjustment and Control*, Prentice Hall, October 2001	Book available to order online
11. Power Technologies, Inc., *Interconnection Study for Orchid Hotel Final Report*, PTI Report Pgh-20514-1, December 2002	Company internal report; not provided due to customer sensitive information
12. Nova Energy Specialist, "Quick Discussion of Ground Fault Overvoltage Due to PV Inverters," Sept 17, 2009	See attached Exhibit 3
13. Solar Electric Power Association, Top 10	SEPA website

Utility Solar Integration Rankings: Results of the 2008 Utility Solar Electricity Survey, Report 05-09, 2009	www.**solar**electricpower.org/media/84522/ ***sepa***%20***top***%20*ten*%202009.*pdf*

Electric Power Systems Inc.
Consulting Engineers

HELCO Maximum Penetration of Distributed Generation Study

EPS Job #08-0440

Prepared for:

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Final Report

August 6, 2009

SUMMARY OF CHANGES

Revision Number	Revision Date	Revision Description
1	04-03-2009	Issued for Review
2	08-06-2009	Issued Final Revision

TABLE OF CONTENTS

1 Executive Summary

Electric Power Systems, Inc. (EPS) was asked to evaluate the effect of distributed generation penetration in the Hawaii Electric Light Company (HELCO) system. To perform this study EPS created a set of six base cases that highlighted HELCOs most constrained dispatch scenarios. Several variables were considered to accurately test the HELCO system. Base cases ranged from the daily minimum to the daily maximum loading level. EPS attempted to dispatch the minimum required spinning reserve for each base case. The minimum steam requirement, which was defined in previous studies by EPS, and the amount of As Available generation were additional constraints that EPS considered when creating the base cases.

The scope of this study called for analyzing the impact of distributed generation penetration within the HELCO system. EPS modeled the Distributed Generation (DG) as a constant power source. While there are several types of DG present in the HELCO system, EPS generalized the types and refers to all DG in this report at photovoltaic generation (PV).

Two types of dynamic stability analysis were run to determine the impact of PV penetration on the system. The first set of stability cases were used to evaluate the system response to unit trips as PV is incrementally added. In the second set of stability cases, EPS attempted to determine the amount of PV that could be added to the system such that for certain unit outages, the PV would cause under-frequency load shedding during a trip of generation.

EPS found that under-frequency load shedding (UFLS) and the amount of system spinning reserve available are two major factors in how PV penetration affects HELCO system dynamic response. The following report details the procedures and results of this study.

2 Introduction

HELCO is experiencing an increasing amount of distributed generation projects that want to interconnect with their system. EPS was tasked to perform a study of the existing and future distributed generation interconnected to the HELCO system, determine any adverse impact of the generation, and, if possible, determine the maximum allowable amount of distributed generation.

HELCO and EPS determined that the most effective way to analyze the impact of photovoltaic generation sources (PV) on the system would be evaluate the system response due to generation unit trips and compare system response at varying amounts of interconnected PV. EPS focused primarily on the effects of PV penetration on the system frequency response and on the UFLS scheme in place. The existing HELCO UFLS scheme and a proposed EPS UFLS scheme were both used in this study.

This study assumes that all the PV sources are in compliance with IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems.

3 Studies

3.1 *Power Flow Base Cases*

EPS created six power flow bases cases for this study. The six cases range from the system minimum to maximum loading levels. Table 1 below lists the seix different base case dispatches that were studied.

Table 1 – Dispatches for Power Flow Base Cases

Case Number	1	2	3	4	5	6
Unit						
Hill 6		17.5	17.5		17.5	
Hill 5	8.0	10.5	10.5	10.5	10.5	10.5
Puna Steam	6.0	14.1	14.1	11.1	14.1	11.1
PGV	27.0	27.0	27.0	27.0	27.0	27.0
Keahole 1CTCC	27.3	27.3	27.3	27.3	27.3	27.3
HEP 1CTCC	16.0	28.5	28.5	28.5	28.5	28.5
Keahole second CT - 2CTCC				29.9	29.9	29.9
HEP second CT additional - 2CTCC				31.5	31.5	31.5
As Availables	low	low	high	low	low	high
Wind						
HRD	2.0	2.0	10.0	2.0	2.0	10.0
Apollo	4.5	4.5	20.0	4.5	4.5	20.0
Hydro						
WAIAU 1			0.4			
WAIAU 2			0.8			
PUUEO 3			0.8			
PUUEO 4			3.0			
WRHPC 1			3.0			
WRHPC 2			3.0			
Totals:	90.8	131.4	165.8	172.3	192.8	195.8

EPS chose the six cases in Table 1 to represent HELCO's more constrained operating conditions. Case 1 is the HELCO system minimum load case, and case 6 is the HELCO's peak load case. EPS also looked at four more cases with load levels falling in between the minimum and maximum cases. EPS varied the amount of As Available generation as well as the number of steam generators online to fully test the operating limits of the HELCO system during this study. In cases 1, 4, and 6, the steam unit, Hill 6, was taken offline. The HELCO system has a minimum steam generation requirement of two steam units, and taking Hill 6 offline in the above cases leaves only the Hill 5 and Puna steam generators online. The amount of As Available generation online has been shown in previous studies to affect the dynamic stability of the HELCO system. Because of this, cases with both high and low As Availables were studied.

In each base case, EPS attempted to maintain a minimum of 6 MW of required reserve generation, or spin, online. The 6 MW of spin is typically carried on two out of the following three steam units in the HELCO system, Hill 6, Hill 5, and Puna Steam. Base Case 1 is the minimum load case and due to minimum dispatch constraints carries more spinning reserve than the other five base cases, which have the minimum required spin of 6 MW.

3.2 Dynamic Stability Runs

EPS initially selected four different unit trip scenarios, these were unit trips of Hill 5, Hill 6, Puna Steam, and HEP CT 1. The four unit trip cases were run on each of the six power flow base cases, creating a total of 24 dynamic stability runs. These 24 base cases were then re-evaluated with 2 MW, 4 MW, and 6.5 MW of PV added to each of the dispatches.

A maximum PV penetration value of 6.5 MW was chosen based the minimum amount of As Available generation online in Base Cases 1, 2, 4, and 5, and based on the study results. When PV was added to the base cases, the As Available generation was backed off primarily because these units do not carry spin. Therefore, the 6 MW of required system spin was maintained when the PV generation was added. An under-frequency trip point of 59.3 Hz for the PV generation was assumed and modeled based on IEEE Standard 1547, Table 2 – *Interconnection system response to abnormal frequencies.*

The PV generation was modeled as a constant power injection with an under-frequency trip point of 59.3 Hz. Five equivalent PV generation models were added to the HELCO database. EPS placed the five PV models geographically across the island in a uniform distriubtion. From previous studies completed for HELCO, EPS has found that the HELCO system frequency is basically uniform across the island during unit trips, and therefore the exact placement of the PV models was not a critical factor in this study.

EPS ran simulations with and without the PV generation and determined the minimum system frequency reached in each case and plotted that against the different PV penetration levels. Figures 1 and 2 each show the amount of PV generation on the x-axis and the minimum transient frequency on the y-axis, for each of the six base case power flows, for the trip of the Puna Steam unit. Figure 1 shows the results with the HELCO UFLS scheme in place, and Figure 2 shows the results for the proposed EPS UFLS scheme. The unit trip simulations are unit breaker open events resulting in an immediate loss of generation in the system, not a unit ramp down event. The minimum frequency is the transient frequency dip, and does not represent the settling frequency or the ultimate frequency one would expect based on the unit droop characteristics.

Figure 1 - Minimum Frequency vs. PV Penetration

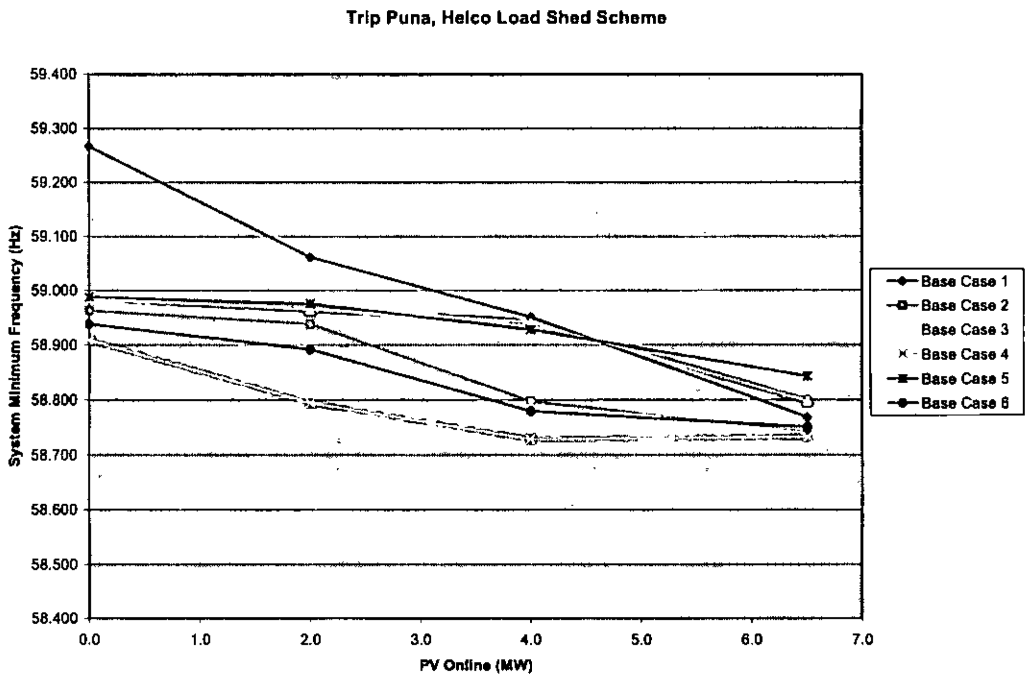
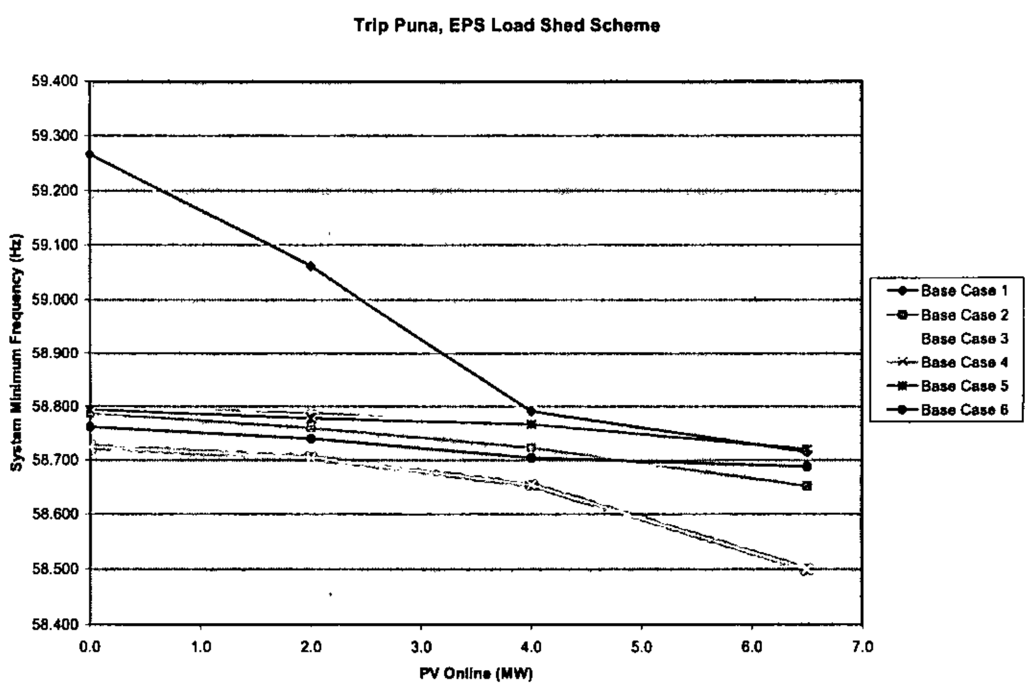


Figure 2 – Minimum Frequency vs. PV Penetration



In both Figure 1 and 2, case 1 has a better system response due to the Puna Steam unit trip when there is either 0 MW to 2 MW of PV online, as compared to the other cases. This is because base case 1 has less generation output for Puna Steam than in the other base cases. Additionally, more spinning reserve is online in base case 1 than in the other base cases, and the first stage of load shedding is not reached until PV penetration is at 4 MW. This is also true for the trip of Hill 5 in Case 1, where Hill 5 is at a lower output than in the other cases.

The transient stability plots for all four unit trip scenarios for both the HELCO and EPS load shed schemes are in Appendix A. The unit trip cases found in Appendix A highlight the effect that spinning reserve and under-frequency load shedding have on PV penetration. For all of the cases with the exception of base case 1, all four unit trip scenarios resulted in stage 1 and / or stage 2 load shedding before PV is added to the system. In most cases, the amount of load shed in stages 1 or 2 was sufficient to immediately stop the frequency decay. As a result, the amount of PV that can be added to the system for these cases, without any additional frequency decay, is equal to the amount of "extra" load shedding. The extra amount of UFLS is the amount of load in excess of the required amount to stop the frequency decay. Therefore, these results will show a very slight decrease in frequency when PV is added, until we reach the point where additional load shed is required. The load shedding effects actually overwhelm the effect of adding PV generation to the system, up to the point where the load shedding becomes insufficient.

When PV was added, the effect on the system was a slight decrease in the minimum frequency. Load shedding does not occur in the Base Case 1, where no PV is added, for either the Puna Steam or Hill 5 unit trip. When PV is added to these cases a sharp decrease in the system minimum frequency is observed. This shows that when stage 1 under-frequency load shedding has already occurred due to a disturbance, the system is less sensitive to the addition of PV generation.

Table 2 shows the load shed during the 6 different cases for the trip of unit Hill 5 with 6.5 MW of PV online. With the HELCO UFLS Scheme in place, cases 2 through 5 go into stage 2 of load shedding. The EPS load shed scheme only reaches stage 1, and a lower overall total of load is shed with the EPS Scheme in place.

Table 2 – Stage 1 Load Shedding for Trip of Hill 5, with 6.5 MW PV Online

Base Case	HELCO UFLS Scheme		EPS UFLS Scheme	
	Stage 1, 59.0 Hz	Stage 2, 58.8 Hz	Stage 1, 58.8 Hz	Stage 2, 58.7 Hz
1	3.84 MW		7.82 MW	
2	5.45 MW	9.44 MW	16.61 MW	
3	6.71 MW	11.45 MW	13.46 MW	
4	7.45 MW	12.46 MW	14.45 MW	
5	8.16 MW	13.34 MW	15.77 MW	
6	8.55 MW		16.53 MW	

The original analytical approach discussed by HELCO and EPS was the evaluation of the unit trips described above. These results clearly indicate an interaction between the amount of PV generation, the size of the unit trip, and the UFLS settings and load shed amounts. In particular, when load shedding occurs, the amount of load shed is normally larger than the amount of tripped generation. When this occurs, the frequency will stop decreasing and will immediately increase. This occurs as long as the amount of load shed exceeds the amount of lost generation. Therefore, the amount of PV generation tripped at 59.3 Hz does not have any significant impact on the minimum frequency, until the amount of PV generation plus the amount of lost generation due to the trip exceeds the first stage of load shedding. Above this amount of PV, the frequency minimum will decrease measurably with increasing PV. Because of the interaction between load shedding and the amount of PV generation, an alternate analytical approach was considered, as described below.

Alternate Analysis

An alternative method to quantify the impact that PV generation has on the HELCO system is by determining the amount of PV that would cause the first amount of under-frequency load shedding, assuming that no load shedding would occur without the presence of PV. HELCO's first stage of load shedding occurs when the system frequency decreases below 59.0 Hz. The under-frequency trip point for the PV generation is 59.3 Hz. With PV added to the HELCO system, any disturbance that causes the system frequency to dip below 59.3 MW will now result in the loss of PV generation. It was our goal to determine the maximum amount of PV generation that could be added such that a case without PV generation that would reach a frequency of 59.3 Hz will now reach a minimum frequency around 59.0 Hz. Any additional PV generation will cause load shedding for the same disturbance.

For this analysis, EPS first chose three base cases that would encompass the operating boundaries of the HELCO system. The cases chosen were Base Cases 1, 3, and 6. The dispatches corresponding to these cases are in Table 1. EPS then determined the amount of generation for each of these base cases that needed to be tripped to result in a minimum transient system frequency of 59.3 Hz. PV was then added incrementally to each of the cases and the generation trip re-run until the PV amount was found that corresponded with the minimum system frequency just above 59.0 Hz. Table 3 below details these amounts for each of the base cases.

Table 3 – PV for no UFLS, HELCO UFLS Scheme

Base Case	Unit trip (MW) to reach 59.3 Hz	PV (MW) added to get to 59.0 Hz
1	6.0 MW	2.5 MW
3	9.8 MW	2 MW
6	6.65 MW	< 1 MW

For base case 3, the amount of generation tripped to get to 59.3 Hz was 9.8 MW. As available generation was tripped (9 MW of Apollo wind and 0.8 MW at Puueo 3 Hydro) thereby not affecting the system spinning reserve. EPS then added PV to the base case and found that 2 MW of PV added to the system combined with the 9.8 MW generation trip resulted in the system frequency dipping close to (but not below) 59.0 Hz. This means that for the medium load level, and corresponding dispatch of base case 3, there is a maximum limit of 2 MW of PV that can be added to the system, otherwise a unit trip of 9.8 MW will cause under-frequency load shedding. Recall that this same amount of lost generation, 9.8 MW, would not cause load shedding if there was no PV generation online. Figures 3 and 4 show base case 3 with no PV added and base case 3 with 2 MW of PV added.

Figure 3 – Base Case 3, Tripped 9.8 MW of Generation, no PV

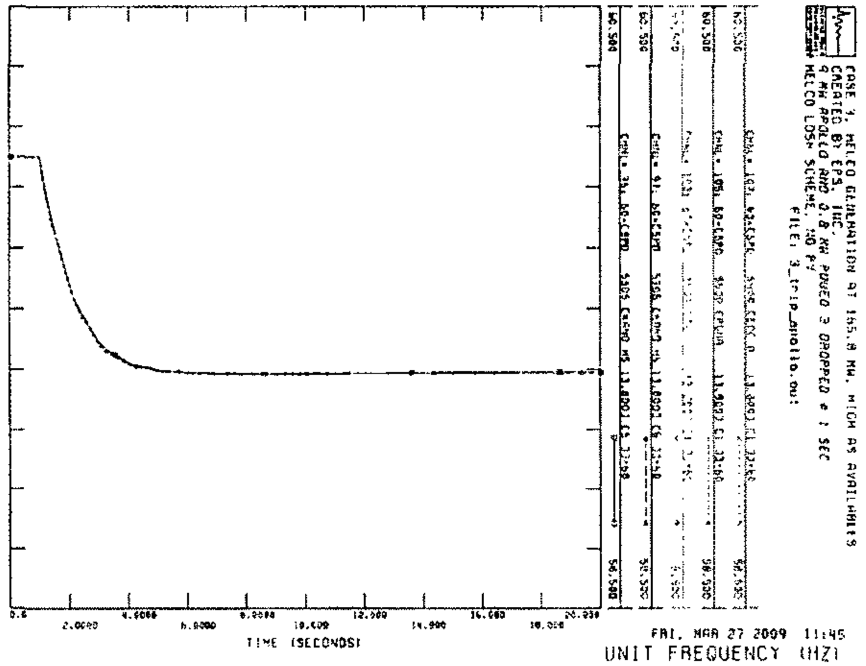
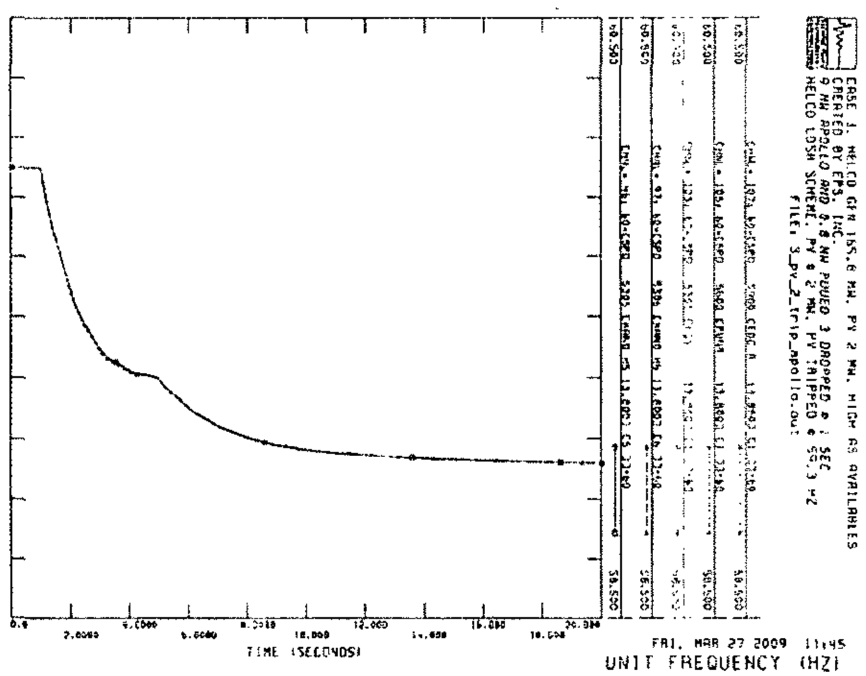


Figure 4 – Base Case 3, Tripped 9.8 MW of Generation, 2 MW PV added



Another factor that impacts the HELCO system response to a disturbance is the governor limits of Hill 6. The dynamic model for the Hill 6 governor within PSS/E (the transient stability software) has a maximum power output that is greater than the maximum output used to calculate the amount of spinning reserve that Hill 6 can contribute. The maximum power output for the Hill 6 governor is 23.0 MW, corresponding to the unit capacity but larger than the ECO or LFC limits in AGC for the unit. This provides an extra 2.5 MW of spin in the transient stability simulation when an under-frequency event occurs. Therefore, in cases with Hill 6 online, the system has a better response to a disturbance because there is more real spin than the minimum requirement of 6 MW of spin. In Table 3, case 3 has Hill 6 online, and cases 1 and 6 do not. Case 3 can withstand a 9.8 MW generation trip and just reach 59.3 Hz, whereas the other two cases can only withstand about a 6 MW generation trip. The extra 2.5 MW of actual spin on Hill 6 in case 3 provides for a better system response.

In Table 3, case 6 is shown as being able to accommodate less than 1 MW of PV added to the system. This case highlights the effect that the minimum spinning reserve has on the system during a generation trip. In case 6, there is 6 MW of spin shared between Hill 5 and Puna Steam. When 6.65 MW of generation is tripped the system recovers and settles to a frequency of 59.3 Hz. However there is very little rebound in the frequency after the minimum is reached. When a small amount of PV is added, such as 1 MW, the system has no spinning reserve to recover from the extra loss of even 1 MW. When generation unit trips occur, close in size to the amount of spinning reserve online, the system becomes very sensitive to any further loss of generation.

The transient stability plots for Base Cases 1, 3, and 6 are attached in Appendix B.

4 Discussion on System Bias

Most of the time, HELCO relies on three units to provide the required system spinning reserve. These units are Hill 5, Hill 6, and Puna Steam. The maximum combined output of these three units is about 47.9 MW. The turbine / governor droop value for each unit is approximately 4%, or 2.4 Hz for a 100% change in unit output. If the three steam units are the only units capable of responding with additional generation during an under-frequency event, then the system bias in the raise direction would be about 47.9 MW per 2.4 Hz. This is equivalent to about 20.0 MW/Hz, or roughly 2.0 MW/0.1 Hz. Note however that this calculation is based on the steady state droop characteristic of the governors, not the transient under-frequency response of the turbine / governors. The transient frequency excursion will be larger, and can be much larger than the expected frequency excursion calculated from the system bias value.

A critical aspect of the impact of PV generation on the HELCO system is the relationship between the PV under-frequency trip point of 59.3 Hz and the first HELCO under-frequency load shed point of 59.0 Hz. These two frequency points are important during the transient response of the system to a disturbance.

If the system bias value of 2.0 MW / 0.1 Hz was a valid measure of the frequency excursion due to a loss of generation, the 0.3 Hz range (59.3 – 59.0 Hz) should be equivalent to 6 MW of additional generation. However, the system bias does not accurately describe the transient frequency dip due to a loss of generation.

Throughout this study, EPS found that using the system bias to estimate the maximum allowable amount of PV is too high. The maximum PV value of 6.0 MW is calculated using a system bias value based on the system responding along the governor droop line to a disturbance. In reality, governors will restore the system frequency to a point determined by the droop line after typically tens of seconds following a disturbance. The minimum frequency due to a disturbance usually occurs in the transient time frame (normally only a couple of seconds) as the turbine governors are beginning to respond but before the governors completely react to the outage. This explains why the maximum PV values found in Table 3 are much smaller than the 6.0 MW value based on system bias and droop characteristics.

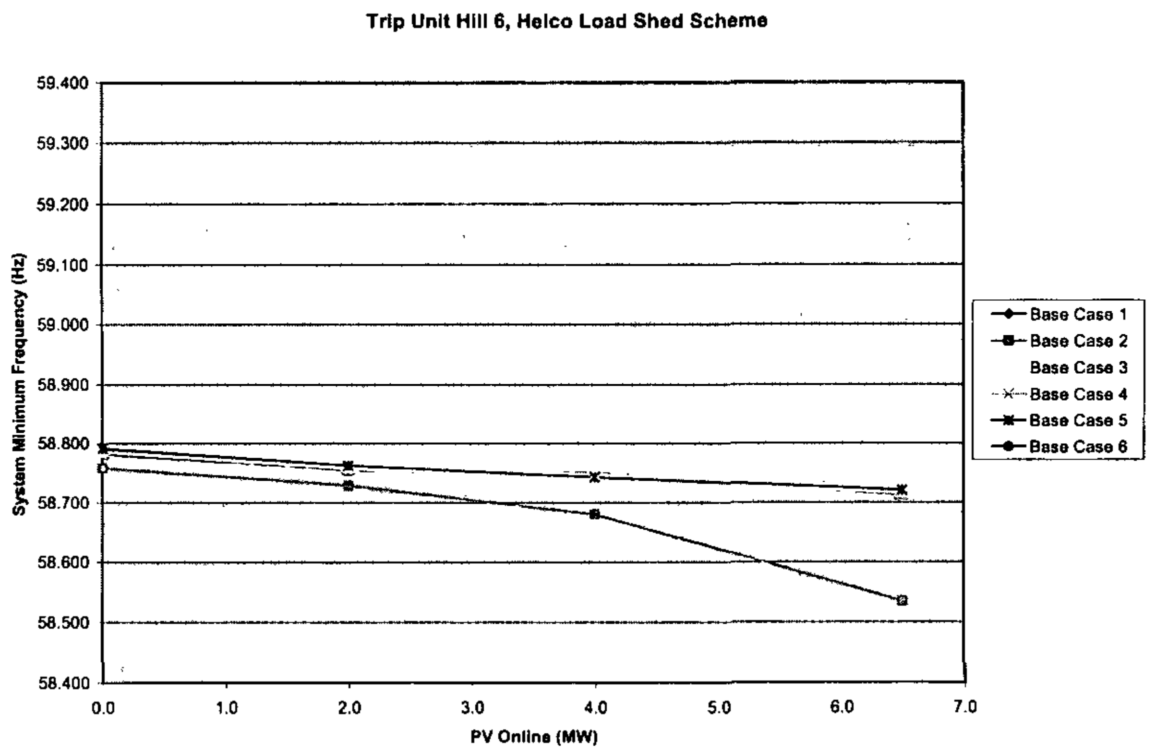
5 Conclusions

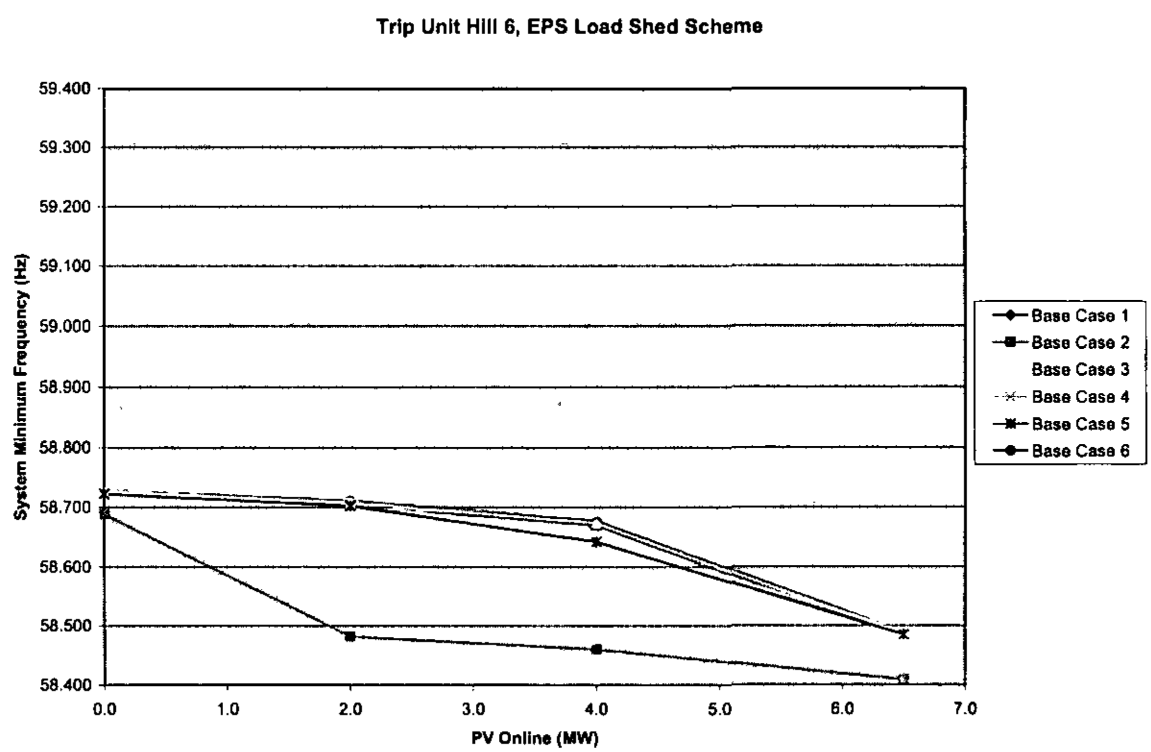
EPS analyzed the effect that PV penetration has on the HELCO system by evaluating the system response to unit trips with varied levels of PV online, as well as determining the PV level that causes the HELCO system to go into UFLS.

The first evaluation used 4 different unit trip scenarios and a range of zero to 6.5 MW of PV online. The resulting plots, found in Appendix A, show that if the system reaches the first stage of UFLS due to a unit trip and no PV is online, the addition of PV has a more subtle effect on system minimum frequency decay. In the base cases that a unit trip does not cause UFLS, however, the addition of PV causes a steep decline in the system minimum frequency. UFLS desensitizes the HELCO system response to the addition of PV up to the point of the next stage of load shedding.

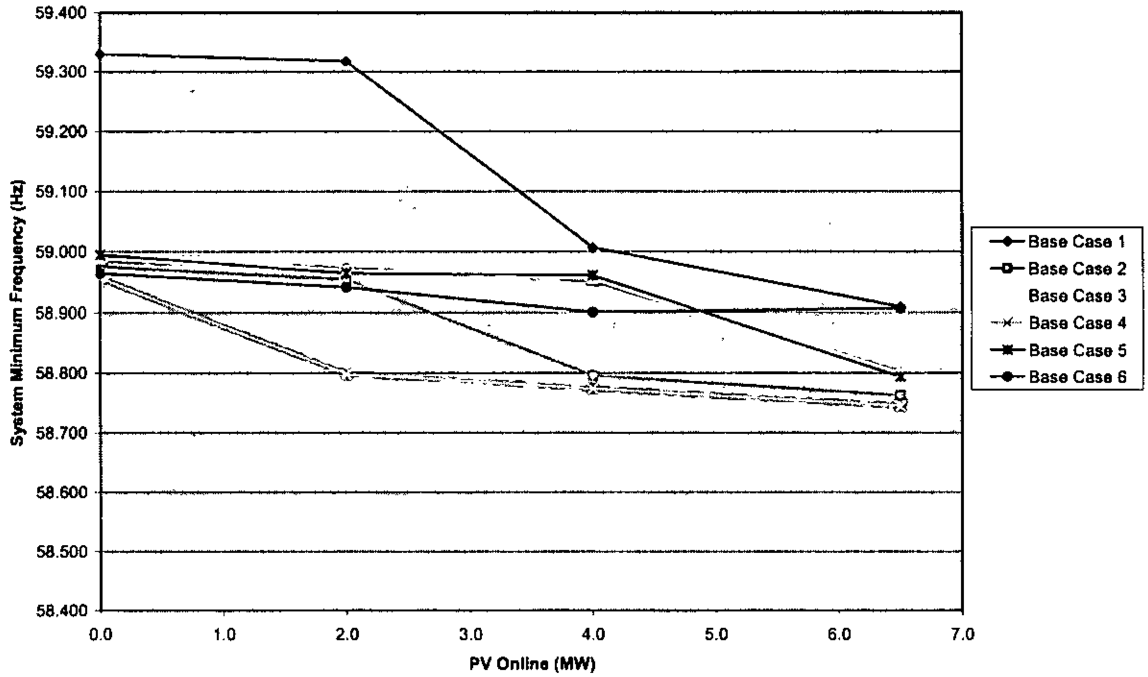
The second set of simulations were used to obtain an amount of PV generation that would cause the HELCO system to go into UFLS when it would otherwise not shed load. EPS found that the minimum frequency reached during a trip of generation was greatly affected by the amount of actual spinning reserve online. This is apparent especially when Hill 6 is online, providing an extra 2.5 MW of spinning reserve due to a difference in unit capacity versus ECO capacity. During this analysis, the amount of PV added to the system that would cause UFLS was consistently around 2 to 2.5 MW. This analysis highlighted the result that the minimum system frequency that occurs during a disturbance appears during the transient time frame, before the governors fully respond along their droop line. Therefore, the affects of droop settings and even AGC are not very pertinent to preventing UFLS when the amount of spinning reserve is small.

Appendix A – Minimum Frequency vs. PV Penetration Plot

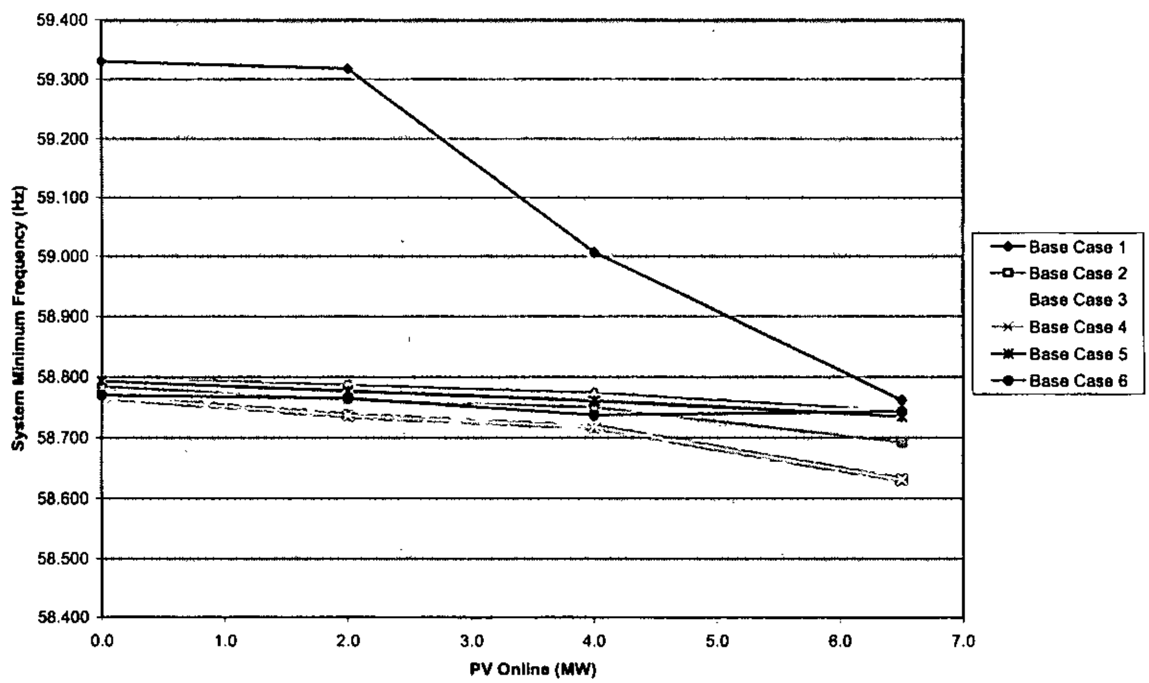

Trip Unit Hill 6, Helco Load Shed Scheme
System Minimum Frequency (Hz)
59.400
59.300
59.200
59.100
59.000
58.900
58.800
58.700
58.600
58.500
58.400
0.0
1.0
2.0
3.0
4.0
5.0
6.0
7.0
PV Online (MW)
Base Case 1
Base Case 2
Base Case 3
Base Case 4
Base Case 5
Base Case 6

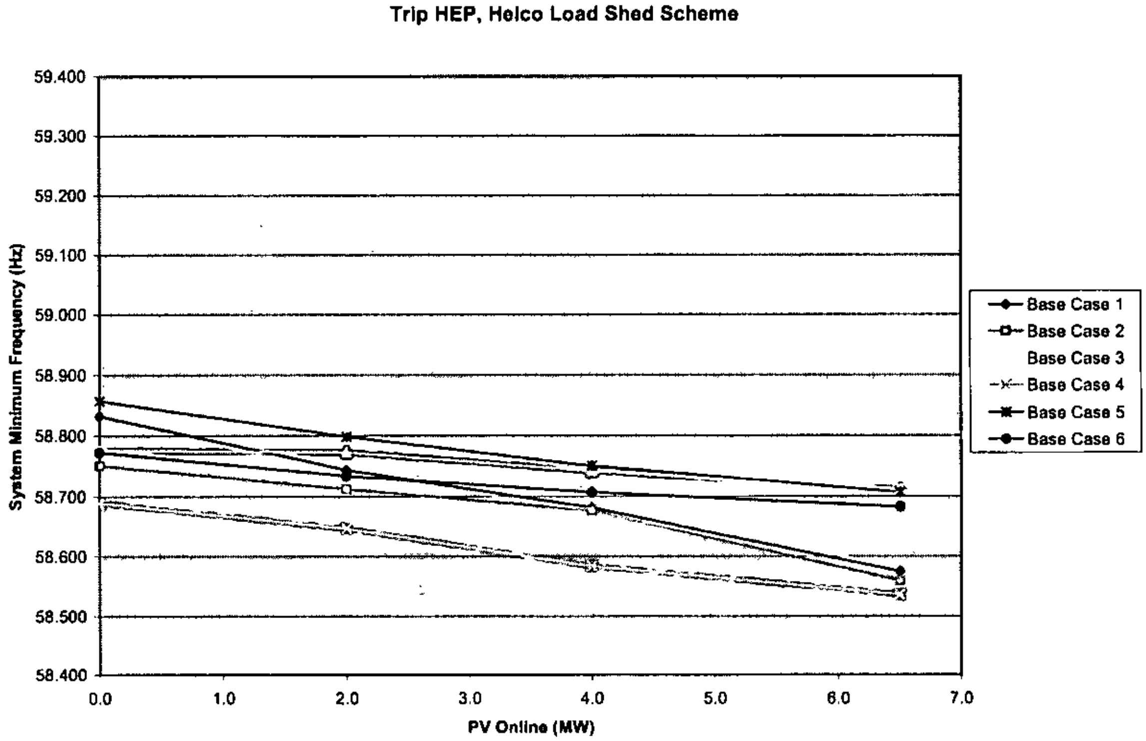

Trip Unit Hill 6, EPS Load Shed Scheme
System Minimum Frequency (Hz)
59.400
59.300
59.200
59.100
59.000
58.900
58.800
58.700
58.600
58.500
58.400
0.0
1.0
2.0
3.0
4.0
5.0
6.0
7.0
PV Online (MW)
Base Case 1
Base Case 2
Base Case 3
Base Case 4
Base Case 5
Base Case 6

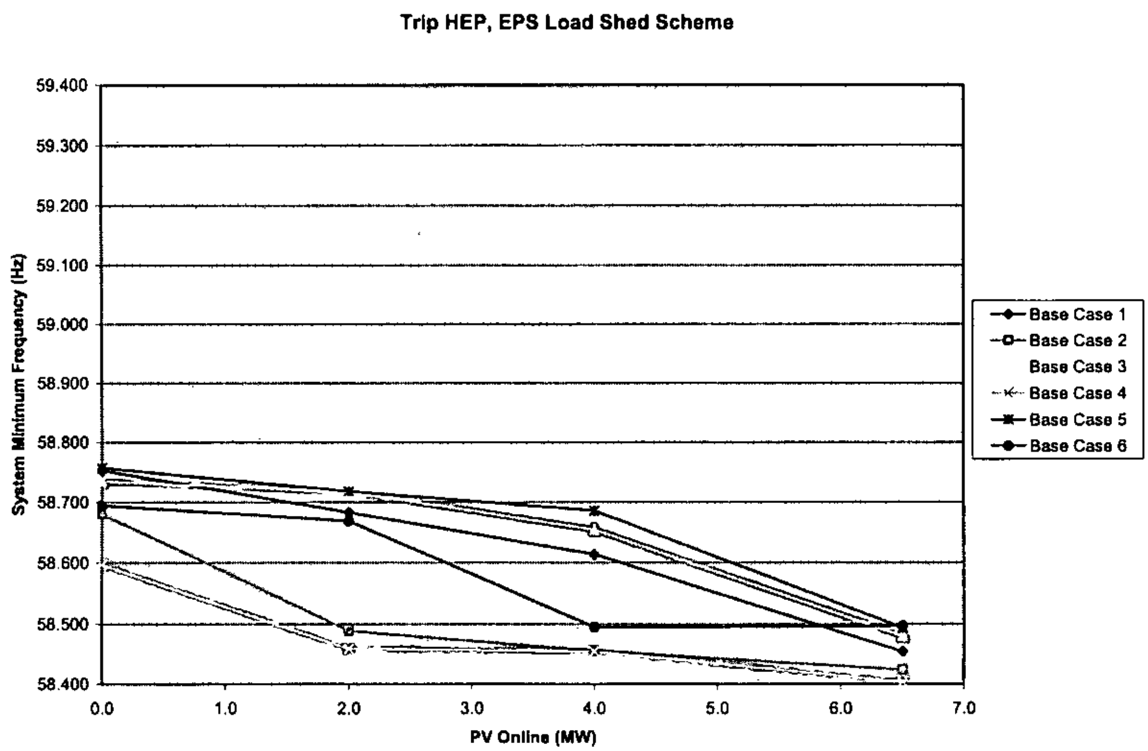
Trip Unit Hill 5, Helco Load Shed Scheme

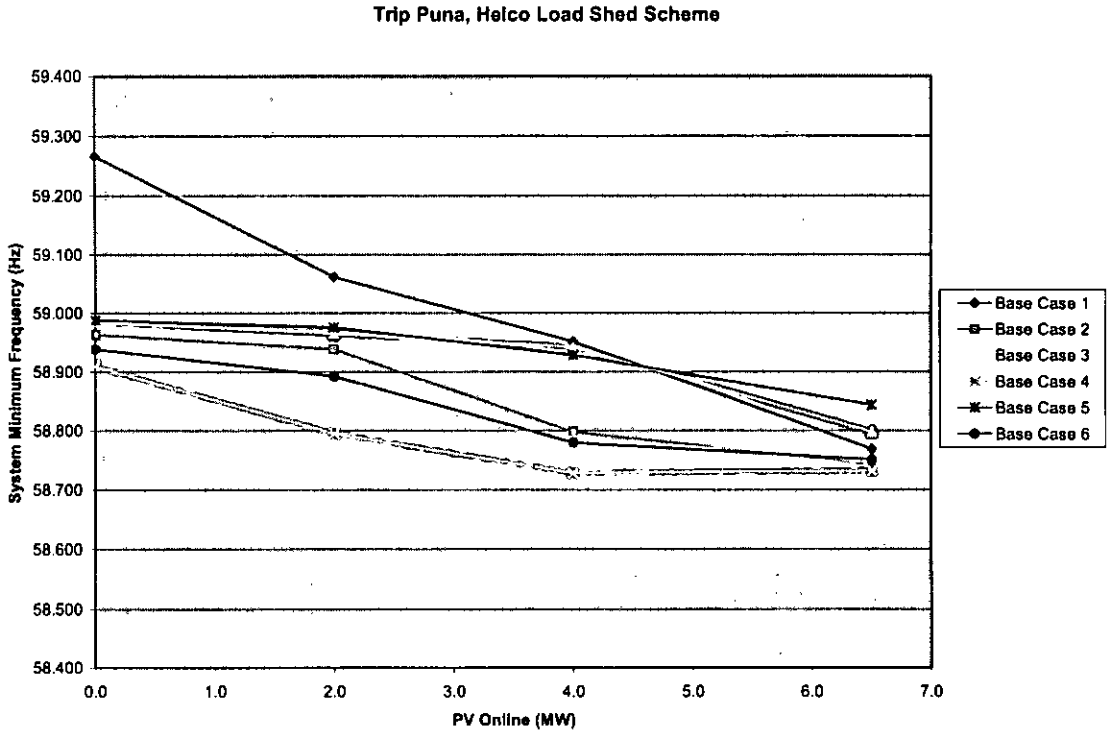


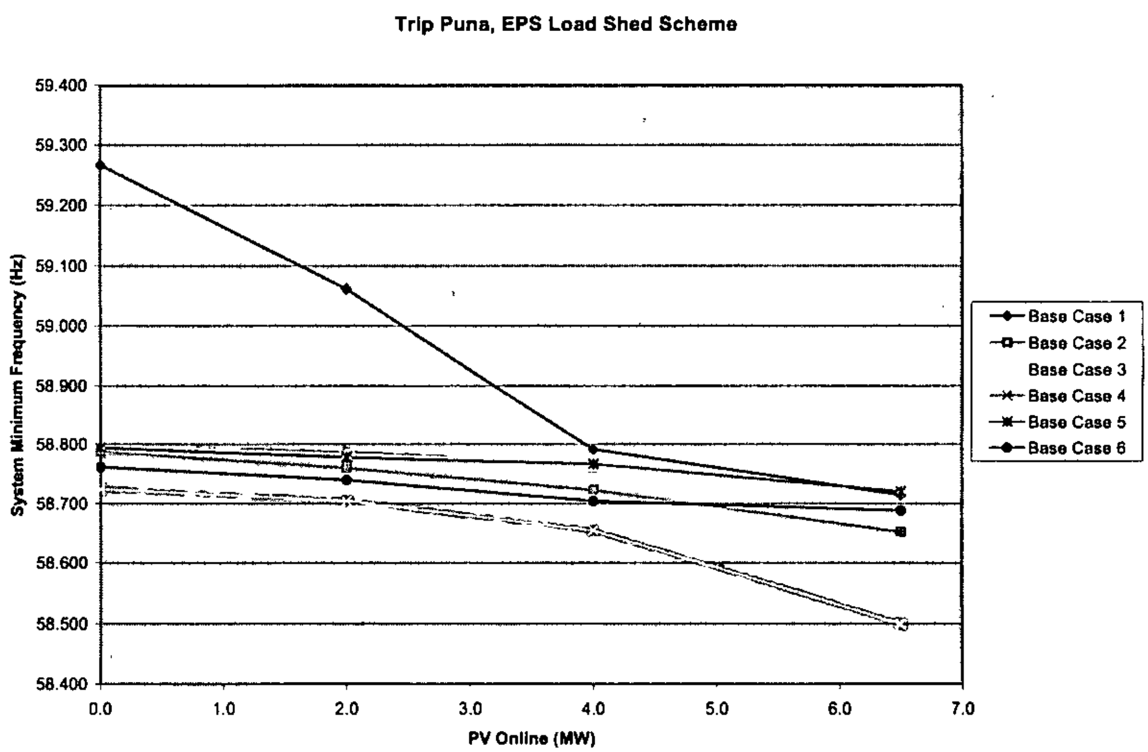
Trip Unit Hill 5, EPS Load Shed Scheme



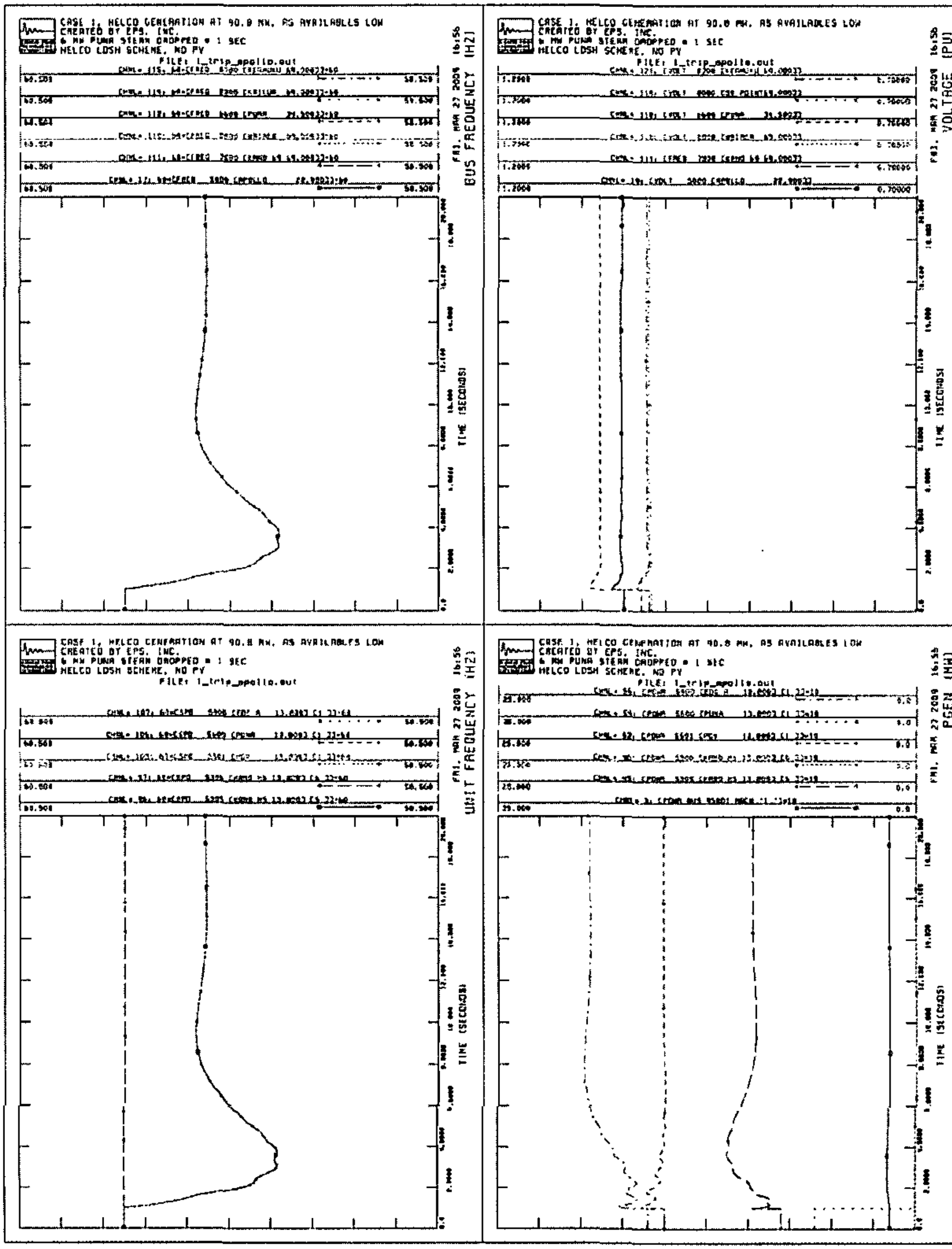

Trip HEP, Helco Load Shed Scheme
System Minimum Frequency (Hz)
59.400
59.300
59.200
59.100
59.000
58.900
58.800
58.700
58.600
58.500
58.400
0.0
1.0
2.0
3.0
4.0
5.0
6.0
7.0
PV Online (MW)
Base Case 1
Base Case 2
Base Case 3
Base Case 4
Base Case 5
Base Case 6


Trip HEP, EPS Load Shed Scheme
System Minimum Frequency (Hz)
59.400
59.300
59.200
59.100
59.000
58.900
58.800
58.700
58.600
58.500
58.400
0.0
1.0
2.0
3.0
4.0
5.0
6.0
7.0
PV Online (MW)
Base Case 1
Base Case 2
Base Case 3
Base Case 4
Base Case 5
Base Case 6

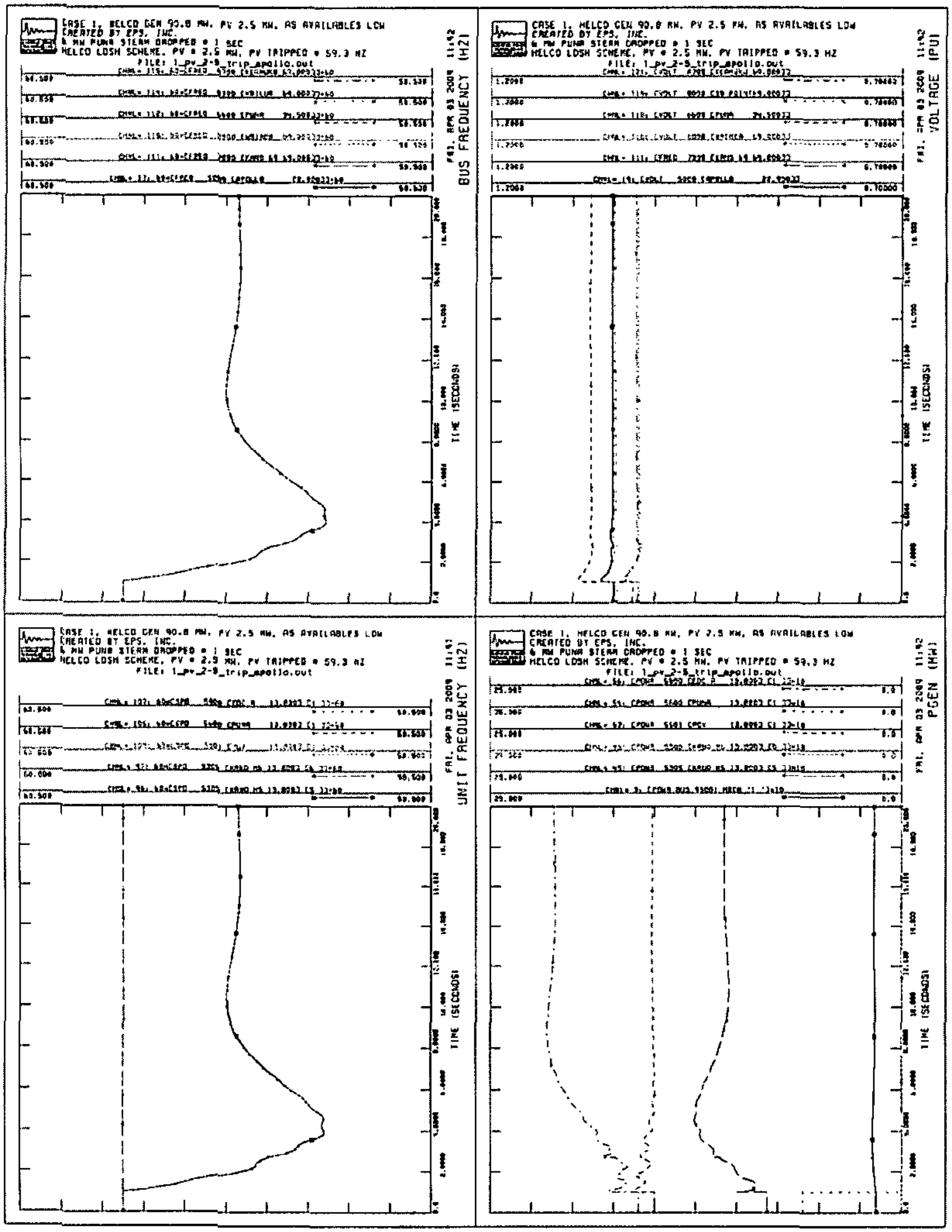

Trip Puna, Helco Load Shed Scheme
System Minimum Frequency (Hz)
59.400
59.300
59.200
59.100
59.000
58.900
58.800
58.700
58.600
58.500
58.400
0.0
1.0
2.0
3.0
4.0
5.0
6.0
7.0
PV Online (MW)
Base Case 1
Base Case 2
Base Case 3
Base Case 4
Base Case 5
Base Case 6


Trip Puna, EPS Load Shed Scheme
System Minimum Frequency (Hz)
59.400
59.300
59.200
59.100
59.000
58.900
58.800
58.700
58.600
58.500
58.400
0.0
1.0
2.0
3.0
4.0
5.0
6.0
7.0
PV Online (MW)
Base Case 1
Base Case 2
Base Case 3
Base Case 4
Base Case 5
Base Case 6

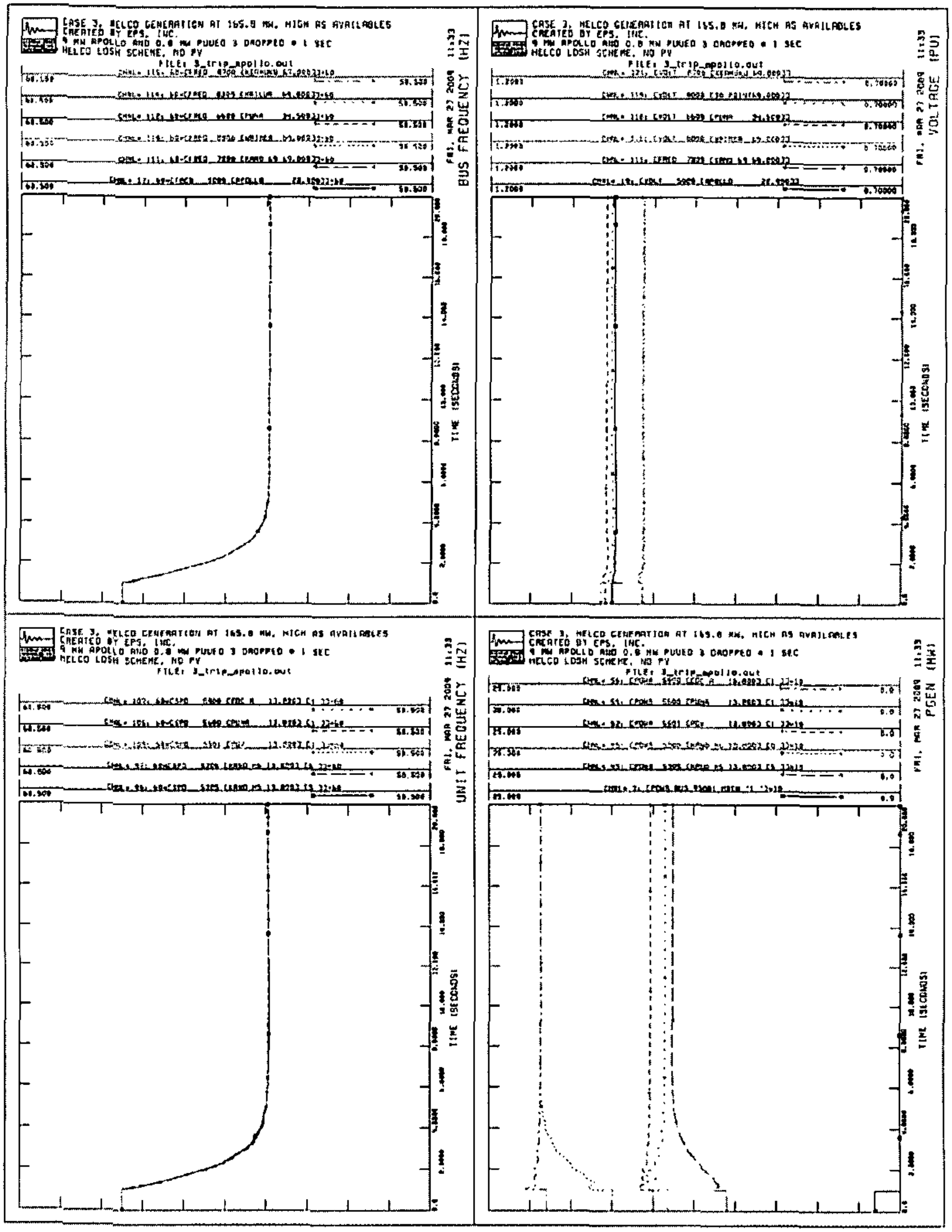
Appendix B – Maximum PV Penetration Stability Plots



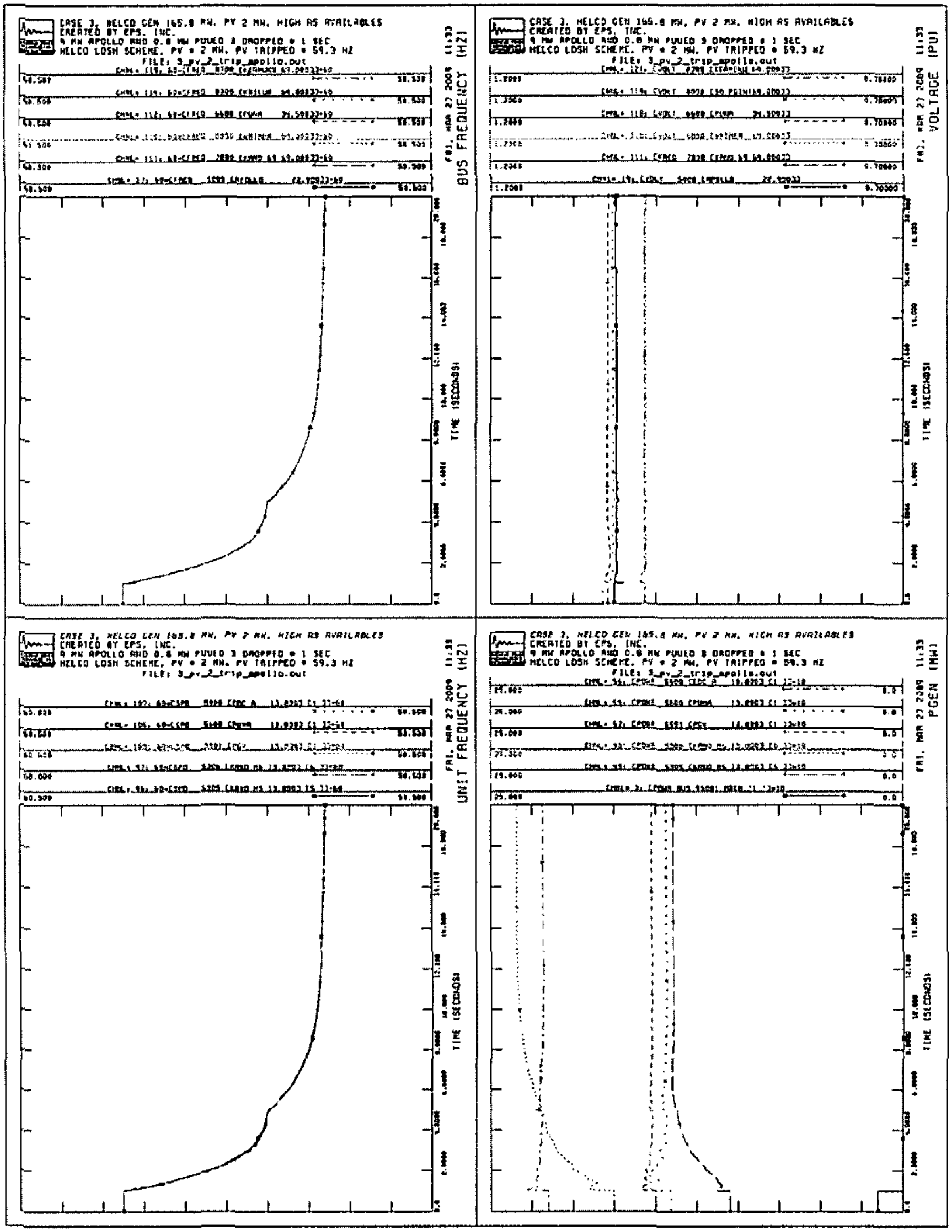
Electric Power Systems Inc.
Consulting Engineers

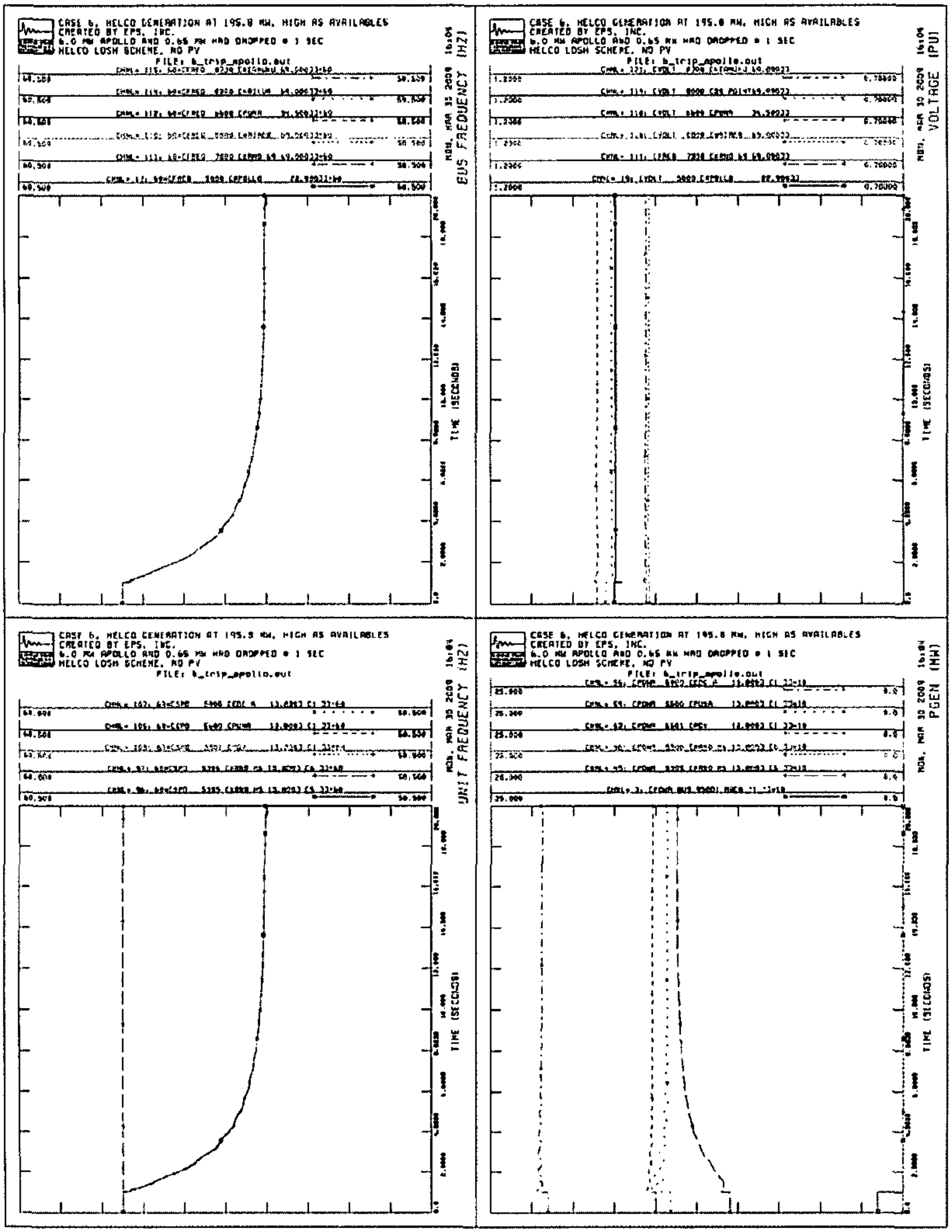


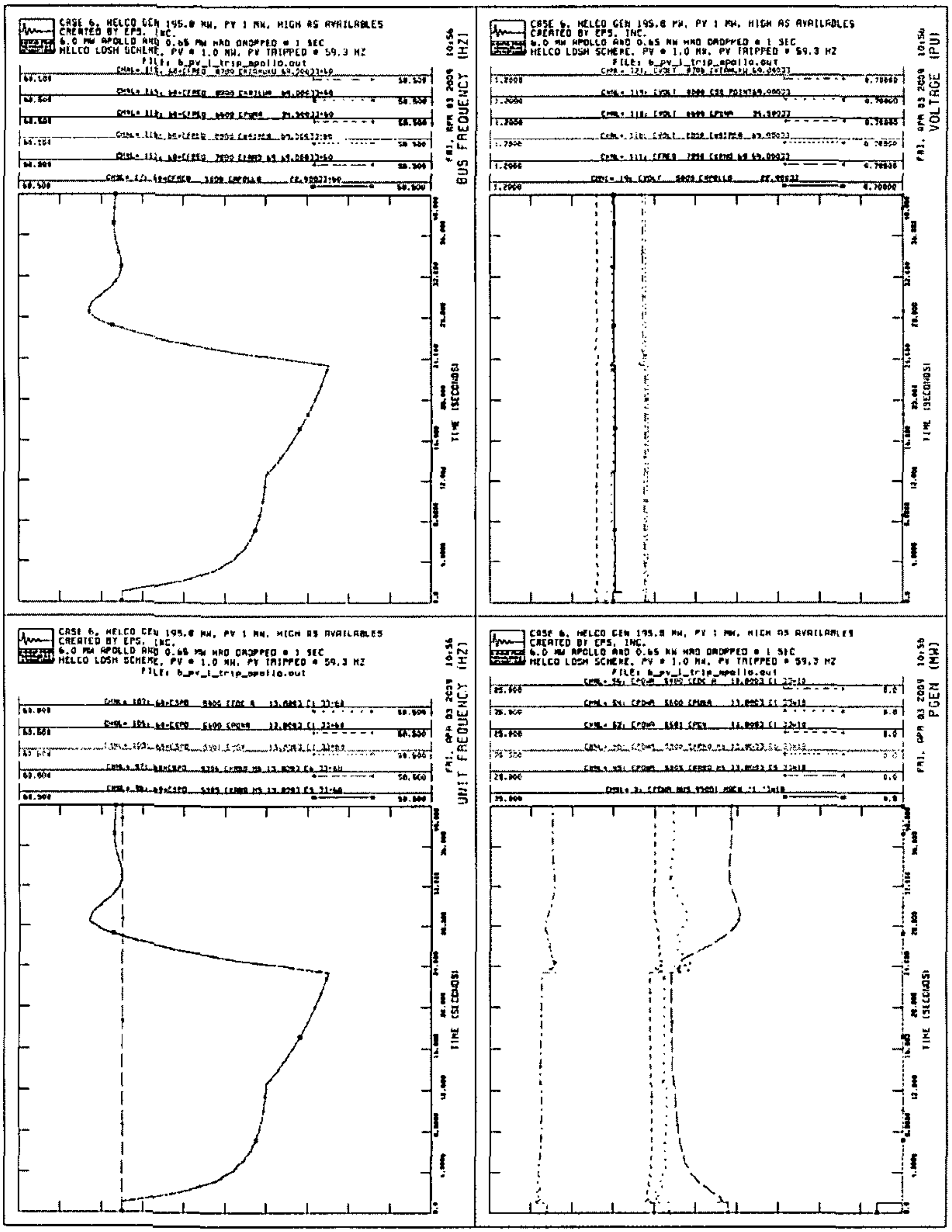
Electric Power Systems Inc.
Consulting Engineers



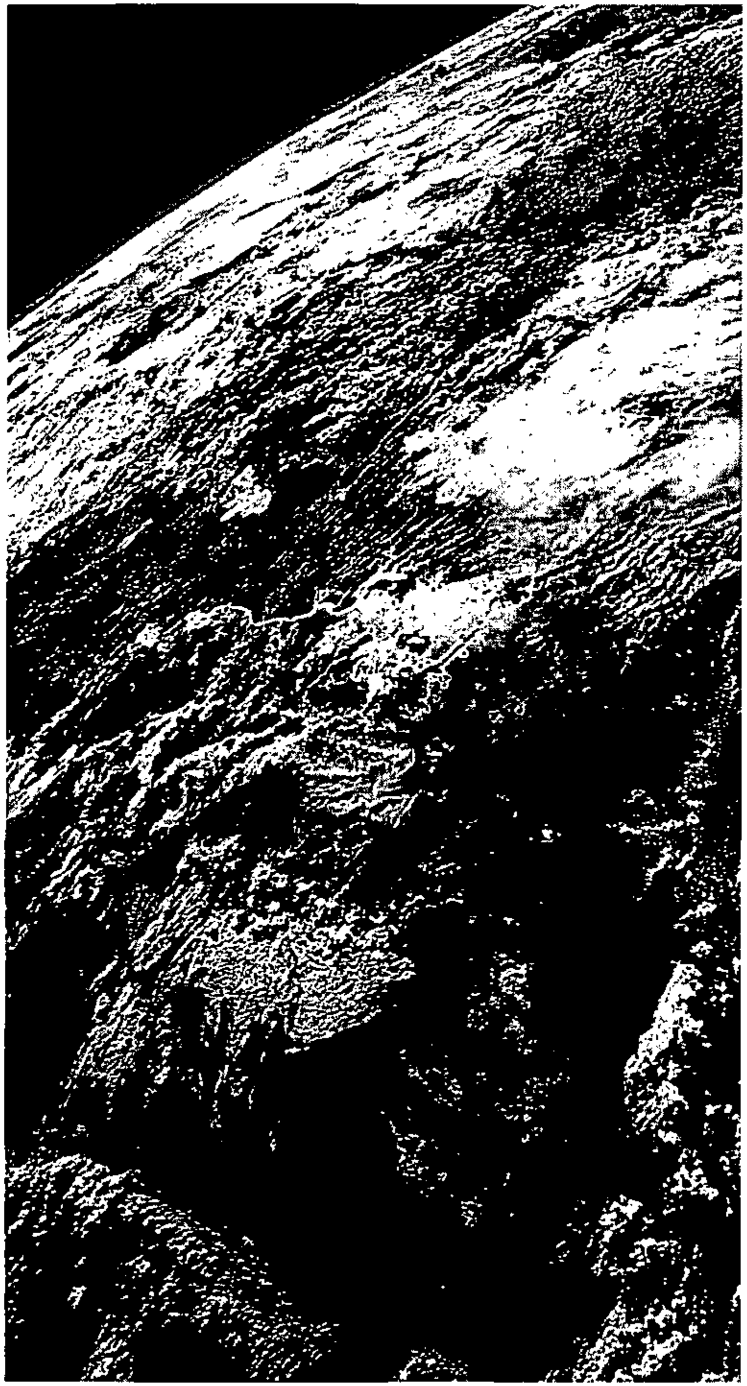
Electric Power Systems Inc.
Consulting Engineers


BUS FREQUENCY (HZ)
VOLTAGE (PU)
UNIT FREQUENCY (HZ)
PGEN (MW)
TIME (SECONDS)


CASE 6, HELCO GENERATION AT 195.8 MW, HIGH AS AVAILABLES
CREATED BY EPS, INC.
6.0 MW APOLLO AND 0.65 MW HAD DROPPED @ 1 SEC
HELCO LOSH SCHEME, NO PV
BUS FREQUENCY (HZ)
VOLTAGE (PU)
UNIT FREQUENCY (HZ)
PGEN (MW)
TIME (SECONDS)



Electric Power Systems Inc.
Consulting Engineers



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HELCO Wind AGC Impact Analyses

Lisa Dangelmaier, HELCO
Daniel Brooks, EPRI

UWIG Spring Meeting
Fort Worth, TX
April 17, 2008

BP-HECO-IR-30
DOCKET 2008-0273
EXHIBIT 2

HELCO System Overview and Op Practices

- HELCO is an autonomous grid
- Automatic Generation Control (AGC)
  - frequency control
  - economic dispatch (CFC mode)
- Large percentage of "fixed" and non-regulating generation
- Large percentage wind energy (15-20%)
- Operate with minimal spinning reserve to minimize fuel costs

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DOCKET 2008-0273
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PAGE 2 OF 16

HELCO System Overview and Op Practices

- 30 MW geothermal (27 must take off peak)
- 15 MW run-of-river hydroelectric
- 33 MW Wind
  - Apollo 20.5 MW -- In service April 3, 2007
    - 2007 capacity factor = 61% (includes curtailment)
  - HRD 10.56 MW -- In service May 19, 2006
    - 2007 capacity factor = 37% (includes curtailment)
  - Lalamilo 2 MW
- Typical MW net to system
  - minimum: 95 MW
  - day peak: 170 MW
  - eve peak: 190 MW

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PAGE 3 OF 16

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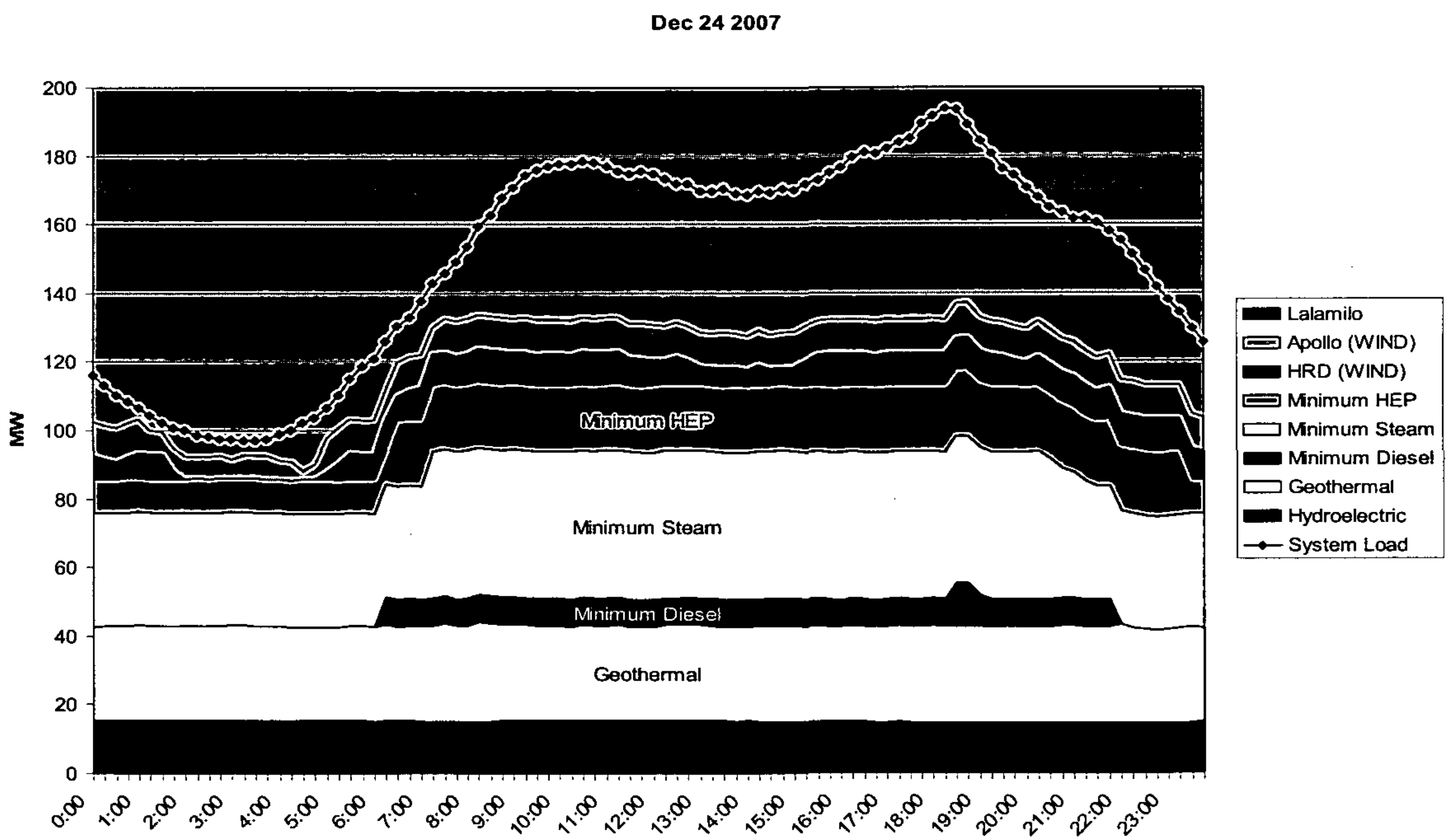
HELCO System Overview and Op Practices



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Phase 1 Results -- Impacts to AGC Performance

- Effectiveness of AGC modifications managing the HRD 10.56 MW wind farm evaluated
  - Most significant improvement came from tuning AGC unit and area parameters
- Data showed that, following AGC improvements, during high wind:
  - Frequency performance was 10-30% lower
  - AGC control actions larger in number and magnitude

AGC State	4-Sec ACE		4-Sec Freq Dev		Total Control Actions	
	STD	Range	STD	Range	#	MW Trav.
Before AGC Modifications	16.3%	21.8%	30.4%	16.7%	18%	134.9%
After AGC Modifications	9.1%	11.7%	15.2%	14.2%	34%	29.0%

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Phase 2 - More Wind → Further Analysis

- Phase 2 of the project was to analyze the impact of the 20.5 MW Apollo wind plant operational April 2007

  Total wind capacity → 33 MW
- The Apollo impact on frequency control was greater than anticipated (perhaps due to wind pattern?)

Most sigificant impacts:

- The second-to-second variability of the wind forces AGC to allow larger frequency deviations;
  - Control deadband +/- 0.2 Hz during minimum load conditions
- Forced allocation of reserve among several units (no longer allow reserve allocation to be determined economically)

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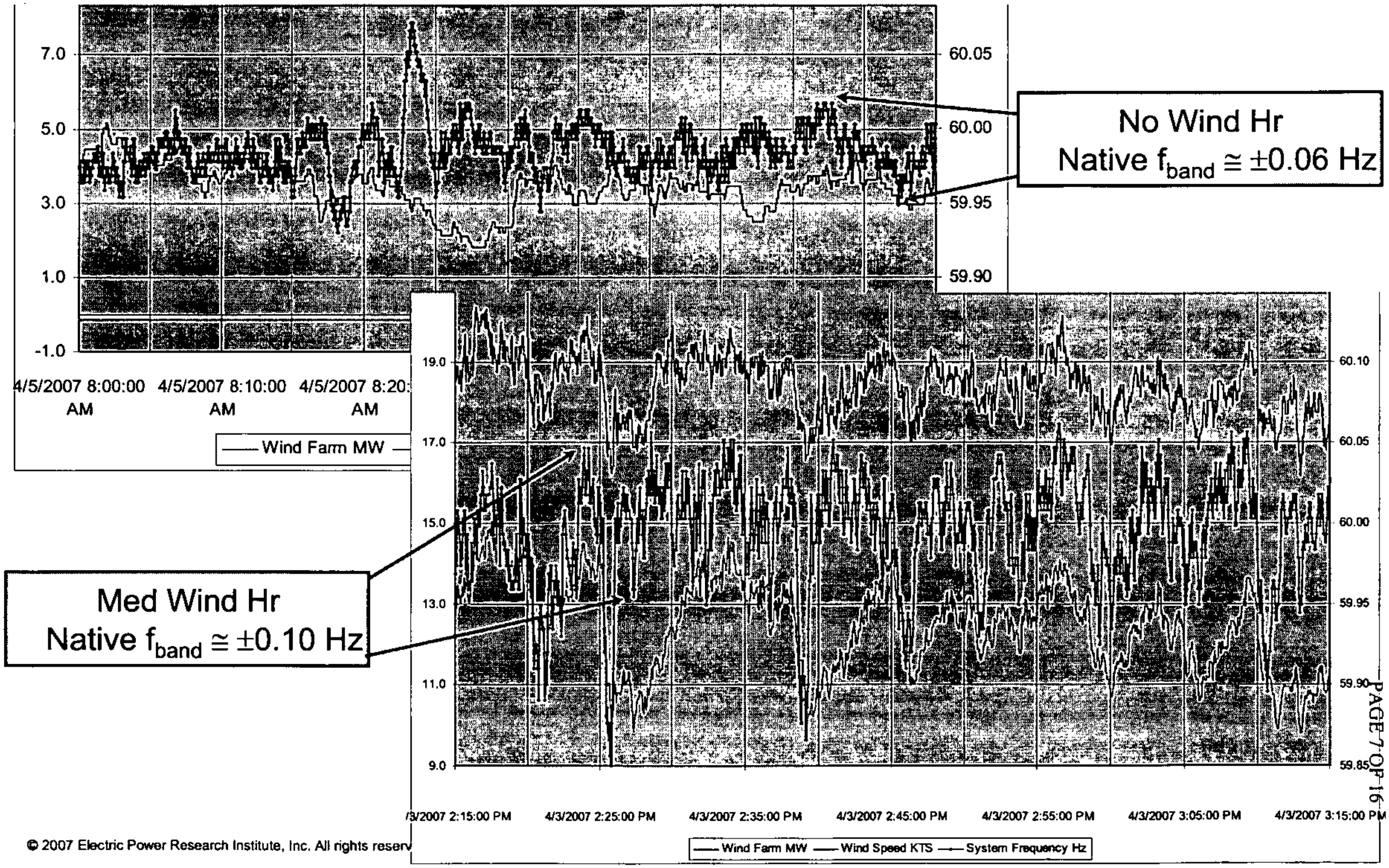
AGC Model/Control Settings Review



Phase 2 – Post AGC Adjustment Data Analysis

- Phase 2 Objectives
  - quantify frequency impact after AGC improvements
  - examine worst impact periods to identify possible mitigating control or operational strategies

- 819 hrs of 4-sec AGC data -- 35 days during Jun-Jul 2007
- Statistical analysis
  - correlation of wind variability to frequency variability
  - freq and AGC activity for periods of wind/load ramping
- Identify worst impact periods and perform event analysis

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Hourly Data Summary – Wind/Load Ramping

		Low Load Ramping			High Load Ramping			Total		
		Freq. band	Num Ctrl	Travel	Freq.band	Num Ctrl	Travel	Freq.band	Num Ctrl	Travel
Low Wind Ramping	Mean	0.10	198.50	17.10	0.12	216.12	26.04	0.11	226.83	21.49
	SD	0.03	134.75	11.12	0.03	100.87	11.70	0.04	155.35	14.80
	Min	0.05	55.00	3.34	0.06	91.00	10.05	0.04	30.00	0.85
	Max	0.21	710.00	68.07	0.25	596.00	74.78	0.31	942.00	116.40
High Wind Ramping	Mean	0.16	358.94	36.80	0.18	315.88	40.66	0.16	351.38	38.77
	SD	0.07	217.91	16.42	0.14	137.58	21.56	0.09	187.37	18.14
	Min	0.06	86.00	10.28	0.08	130.00	22.73	0.06	83.00	9.84
	Max	0.46	954.00	90.60	1.09	854.00	158.31	1.09	954.00	158.31
Mean – %Inc		**59.6**	**80.8**	**115.2**	**50.5**	**46.2**	**56.1**	**45.9**	**54.9**	**80.4**
SD – %Inc		**101.3**	**61.7**	**47.7**	**316.9**	**36.4**	**84.2**	**139.7**	**20.6**	**22.6**

- Freq band/controls increase during high vs. low wind ramping
  - mean increases 45-80%
  - std dev increases 20% for controls and 140% for freq band
- % increases for high vs. low load ramping smaller

Mean – %Inc		**35.2**	**23.3**	**79.7**	**15.6**	**-13.3**	**10.2**	**27.3**	**3.4**	**41.8**
SD – %Inc		**26.5**	**-9.2**	**39.3**	**131.2**	**-39.3**	**42.0**	**64.9**	**-29.0**	**17.6**

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Analysis of Periods of High System Freq Dev

- Wind ramping also leads to large freq deviations
  - combo of system/wind variables → highest impact

- Analyze 10 hrs w/ highest Δ freq

Month	Day	Hour	Avg Ld (MW)	Avg. Wg (MW)	Δ Wg (MW)	Avg. RegUp (MW)	Δ Freq (Hz)
6	22	14	174.0	23.3	8.1	0.3	0.288
6	20	15	175.3	22.3	3.8	1.1	0.298
7	5	13	176.4	28.4	2.0	4.4	0.313
6	12	23	120.3	13.2	12.4	11.9	0.313
7	10	2	103.9	20.0	9.7	5.2	0.332
6	21	6	135.1	16.5	5.9	19.1	0.347
7	7	1	104.8	19.1	8.4	4.8	0.366
6	7	4	103.8	11.7	17.7	2.9	0.405
6	28	3	102.1	10.3	17.4	1.5	0.459
6	29	20	164.1	22.1	7.9	6.3	1.089

- Analyze 5 hrs w/ high Δ Wg but low Δ freq

Month	Day	Hour	Avg Ld (MW)	Avg. Wg (MW)	Δ Wg (MW)	Avg. RegUp (MW)	Δ Freq (Hz)
6	11	23	120.6	17.7	15.4	9.1	0.151
6	24	16	156.6	16.1	14.8	8.5	0.107
6	7	5	117.9	18.2	14.4	17.0	0.122
7	6	0	113.3	23.4	13.6	17.0	0.117
6	7	1	102.0	13.0	13.5	22.2	0.098

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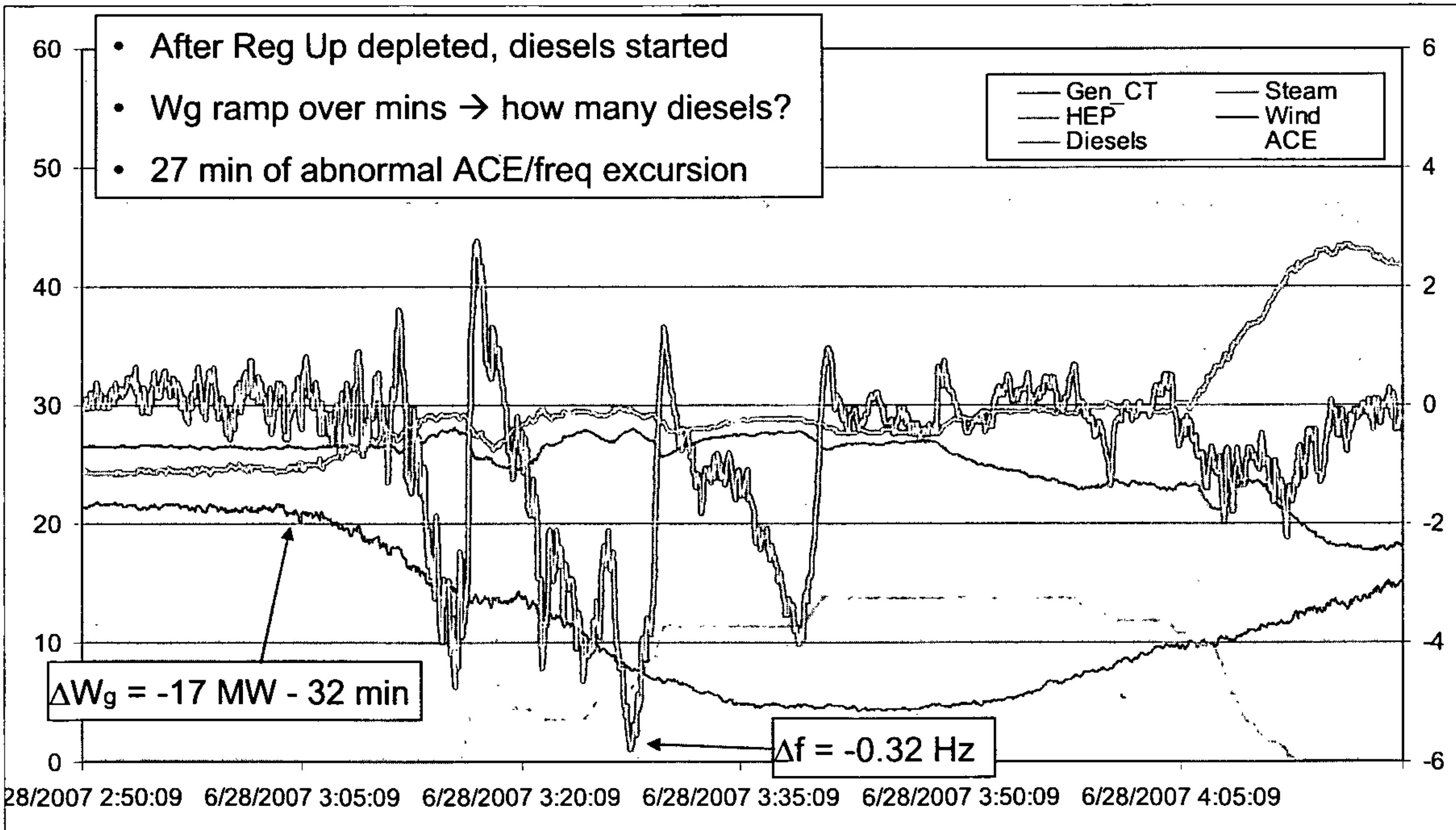
Low Load – Fast Wind Ramp Down Events



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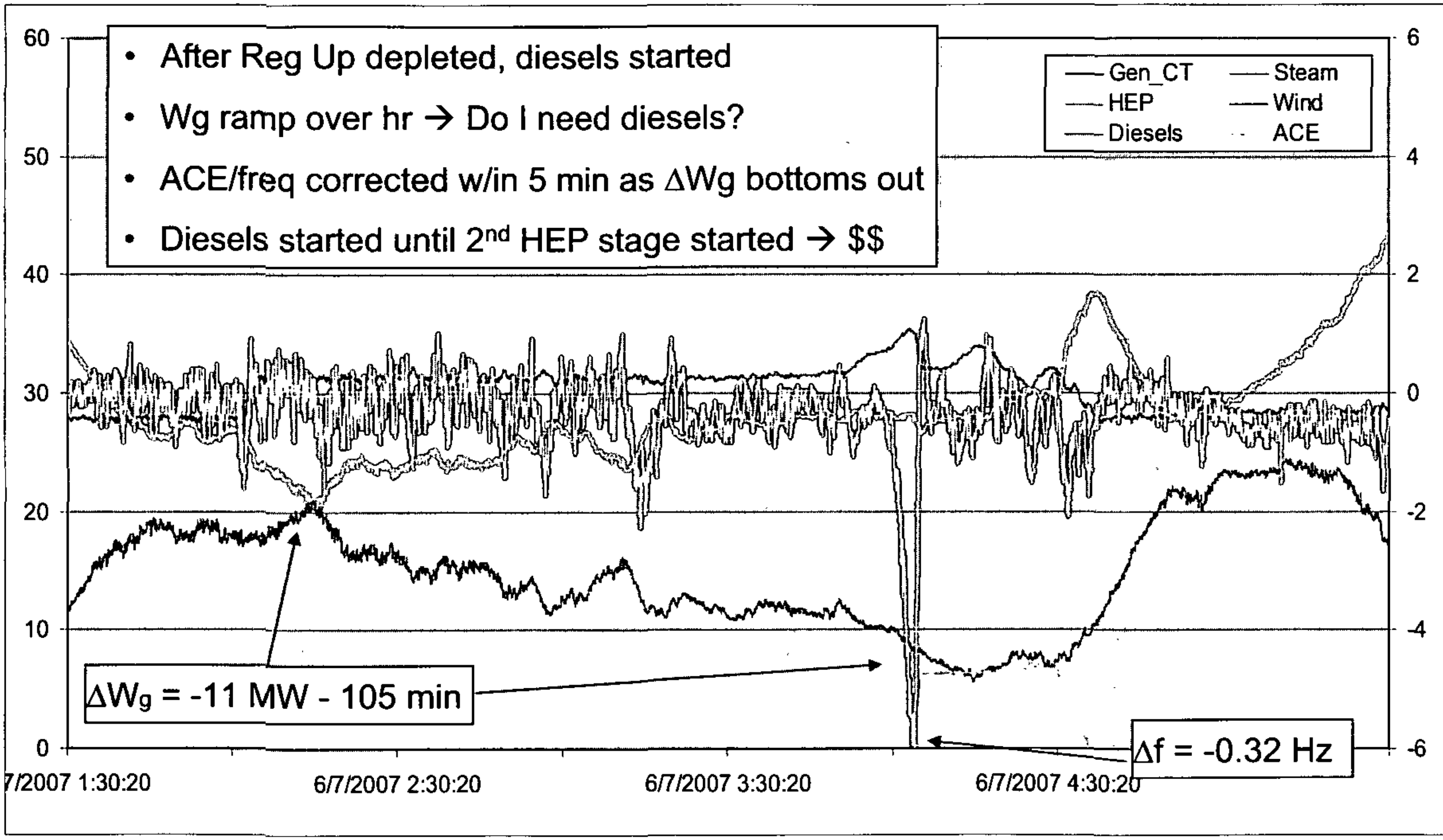
Low Load – Slow Wind Ramp Down Events



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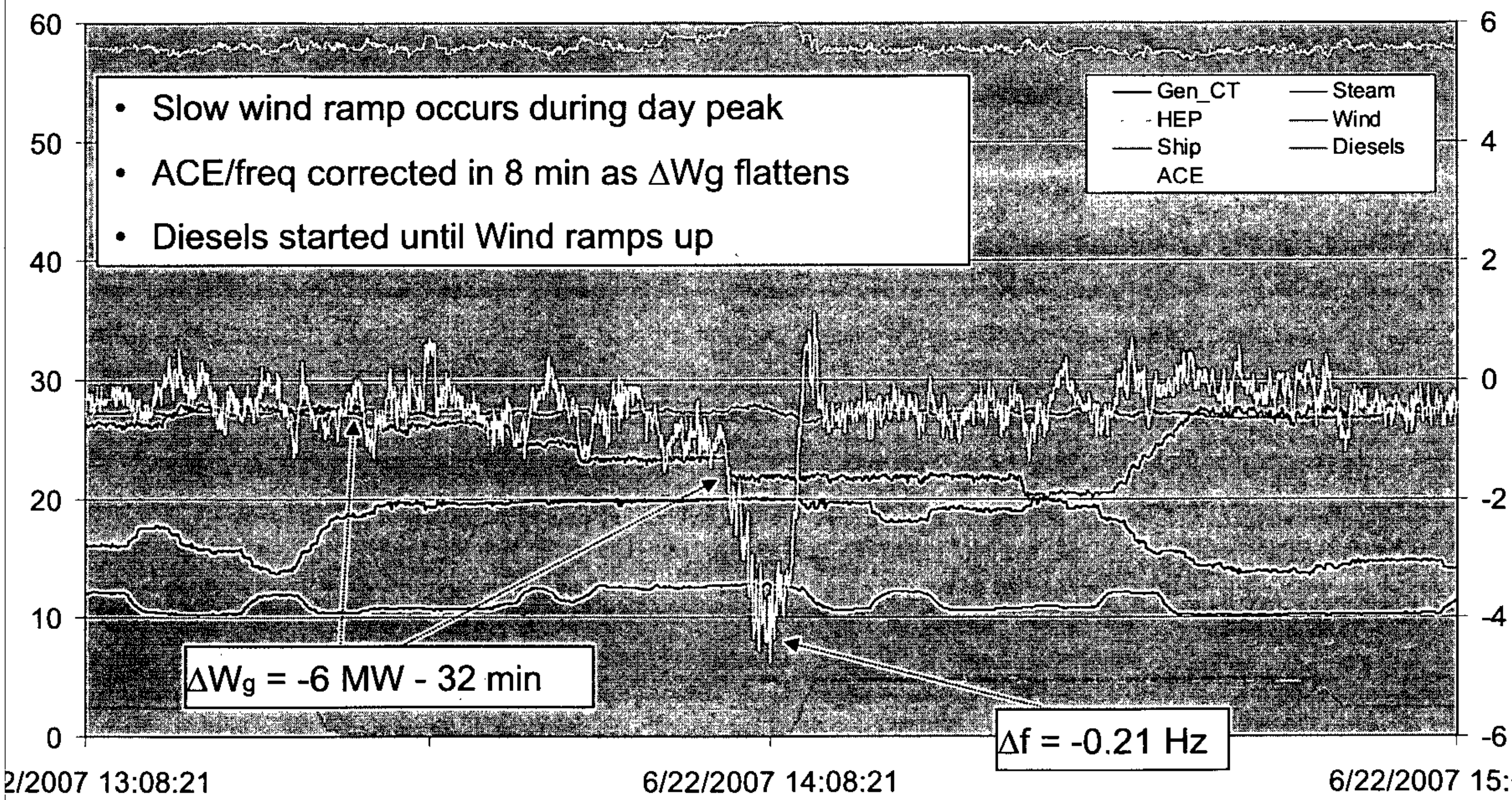
High Load – Slow Wind Ramp Down Events

- Slow wind ramp occurs during day peak
- ACE/freq corrected in 8 min as ΔWg flattens
- Diesels started until Wind ramps up



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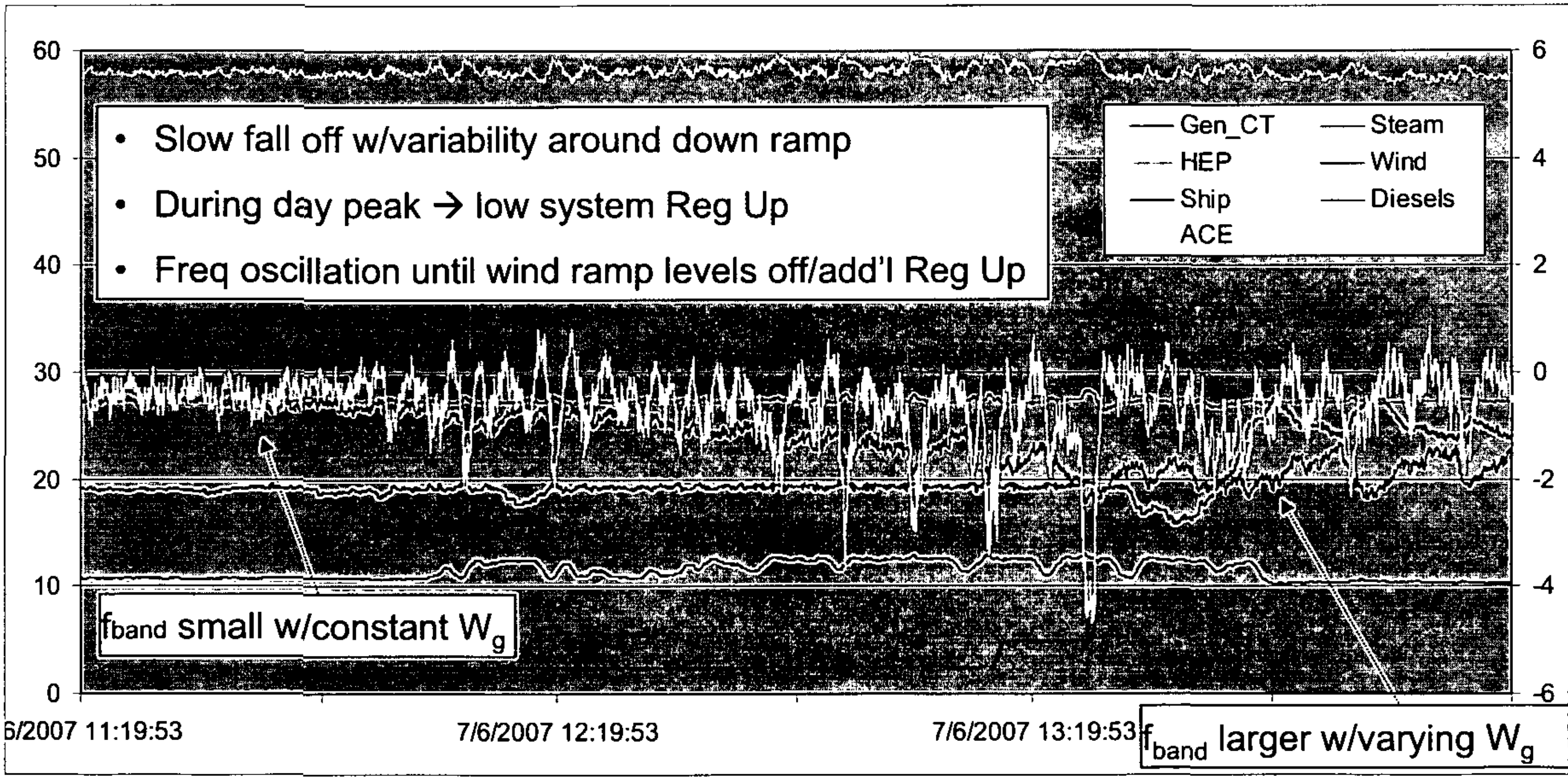
High Load – Slow Wind Ramp w/Oscillation



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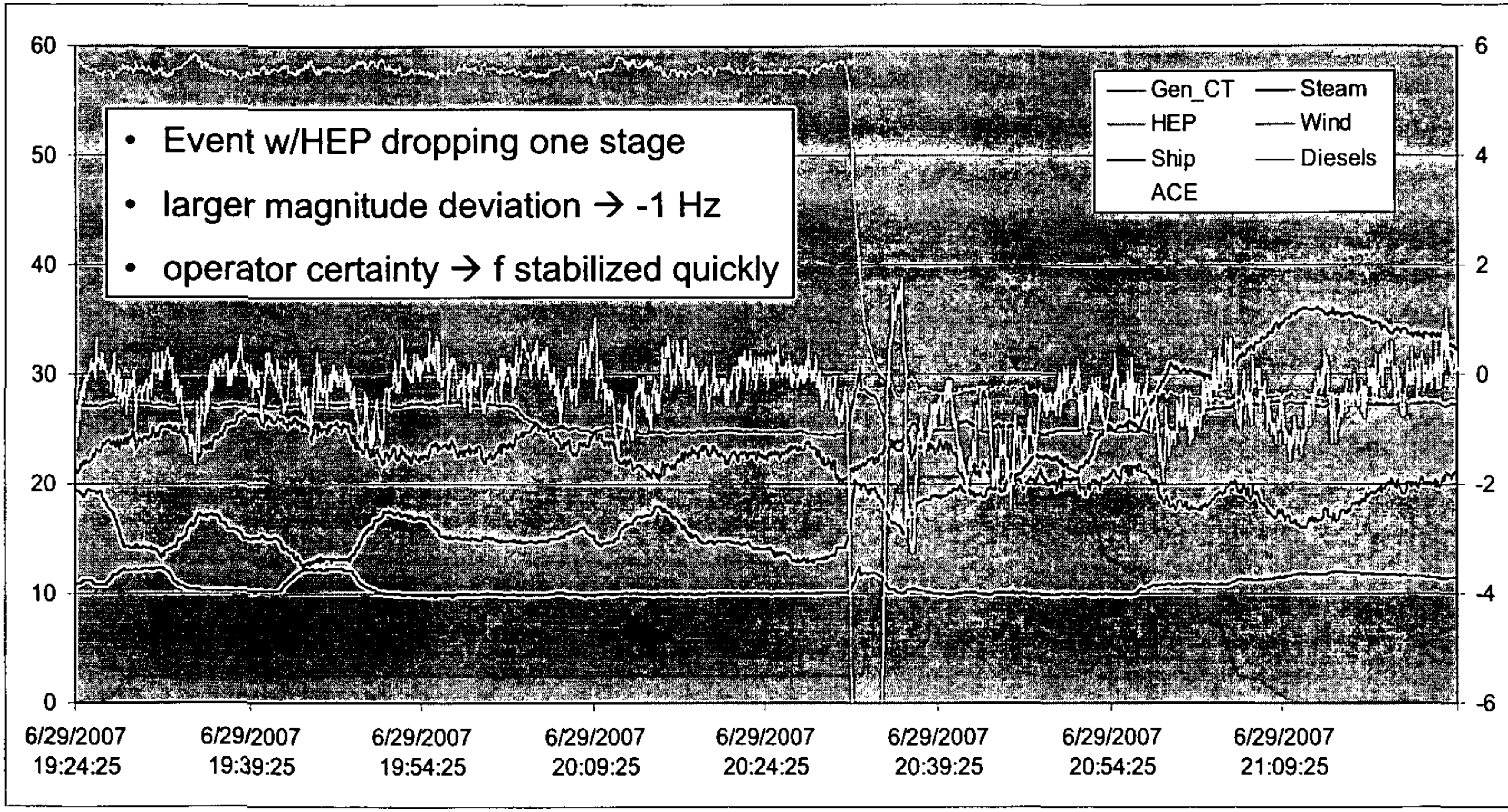
Wind Ramp Down vs. Disturbances



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Conclusions

- Implications on security/reliability
  - variability → freq deviation increase w/wind
    - second wind plant increased
    - mitigation difficult
  - wind ramping → large frequency events
    - forecasting and add'l reserves can help
    - existing operator tools not designed for wind
- Implications on costs
  - use of diesels to provide emergency reserve
  - add'l steady-state reserve
  - increased control activity on regulating units → increased O&M $

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Quick Discussion of Ground Fault Overvoltage Due to PV Inverters

Phil Barker

Nova Energy Specialists, LLC

September 17, 2009 EPRI Webcast

BP-HECO-IR-30
DOCKET NO. 2008-0273
EXHIBIT 3
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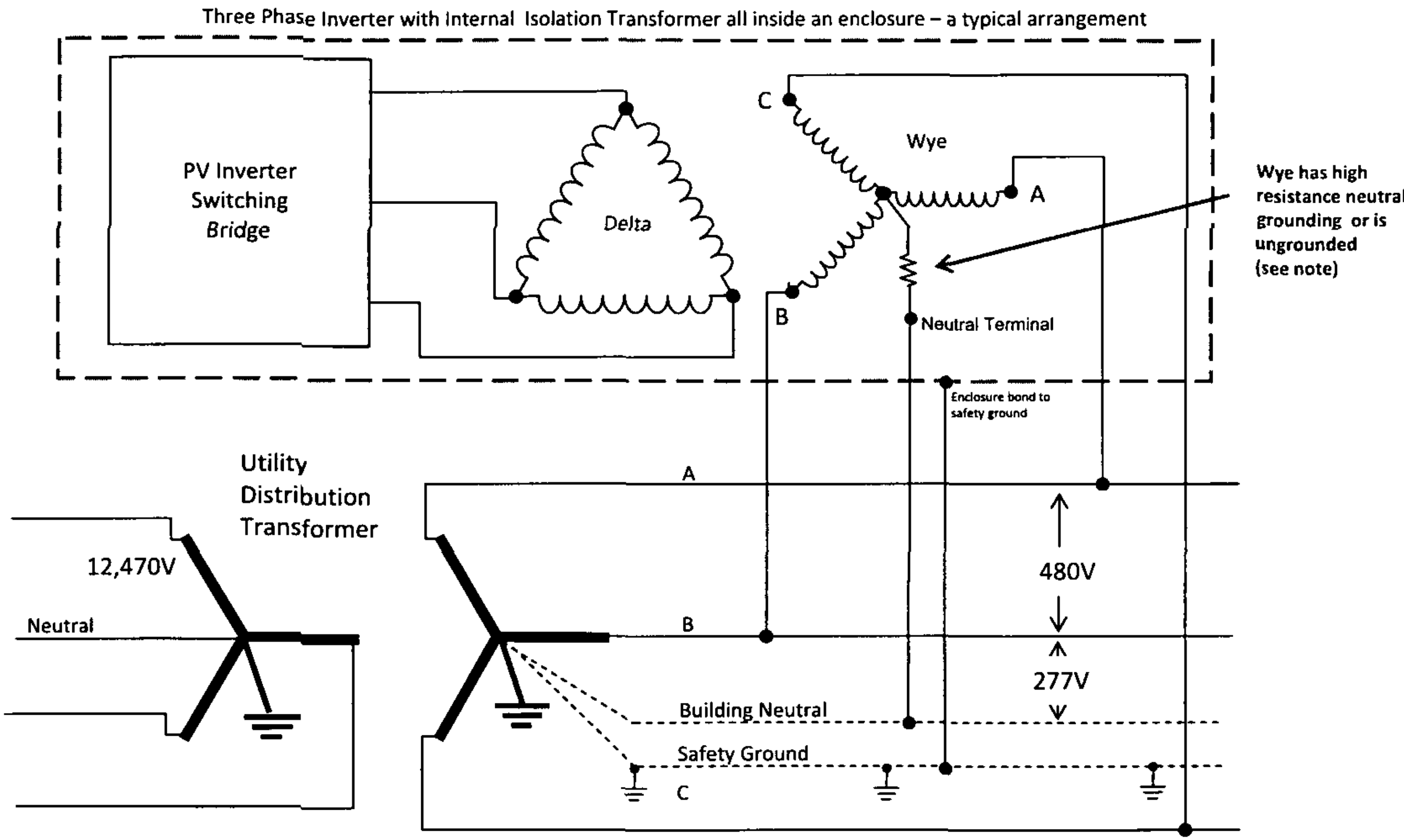
Three Phase Inverter – Neutral Is Typically Not Effectively Grounded



Note: This type of neutral grounding connection is purely to allow inverter to properly sense phase to neutral voltage for protection and control purposes. It is essentially open or high impedance grounded. Either way is not intended for serving zero sequence load current and any unit essentially acts as an ungrounded-neutral type source.

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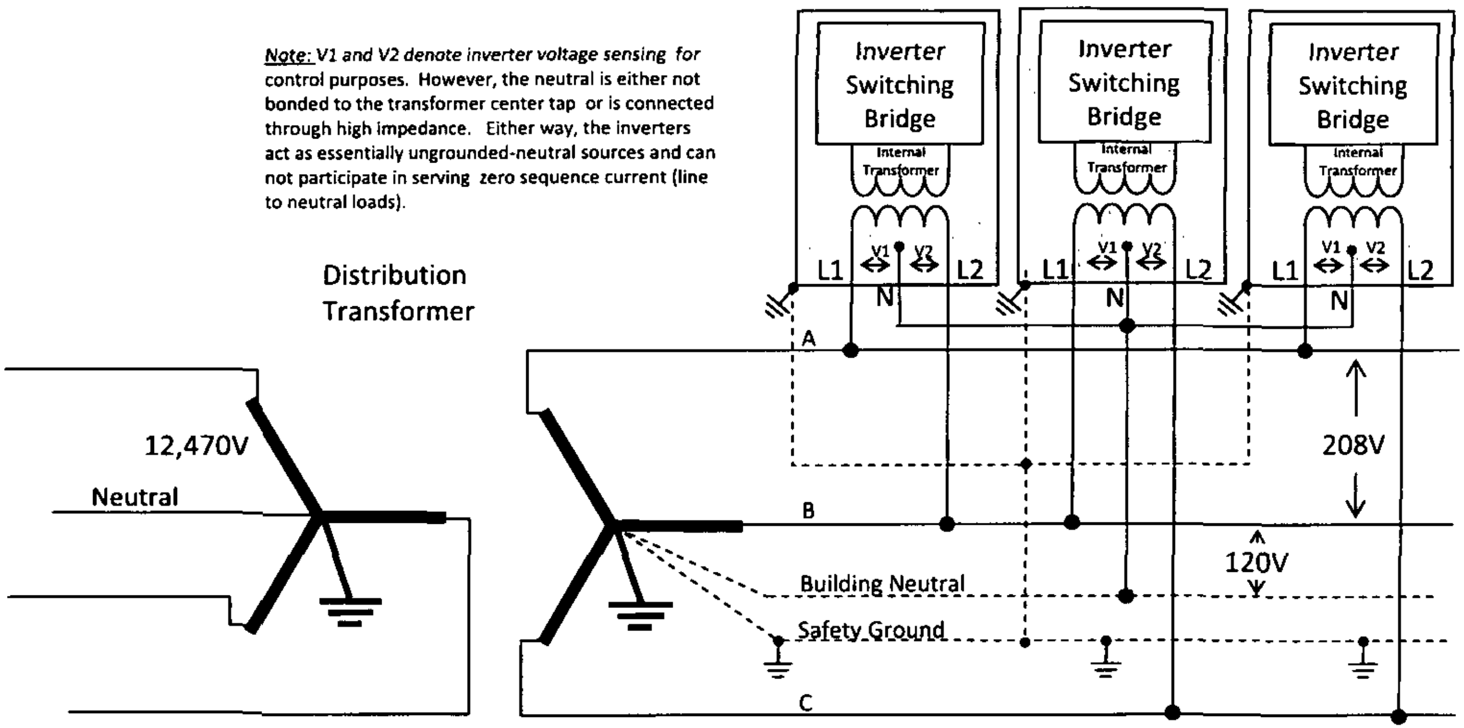
Nova Energy Specialists, LLC Contact: Phil Barker Phone (518) 346-9770 pbarker@nycap.rr.com

Single Phase Inverters Grouped to be a Three Phase Source

(in this case the inverters end up as essentially a *delta connected source* and so the neutral connection is such that they are not effectively grounded sources)



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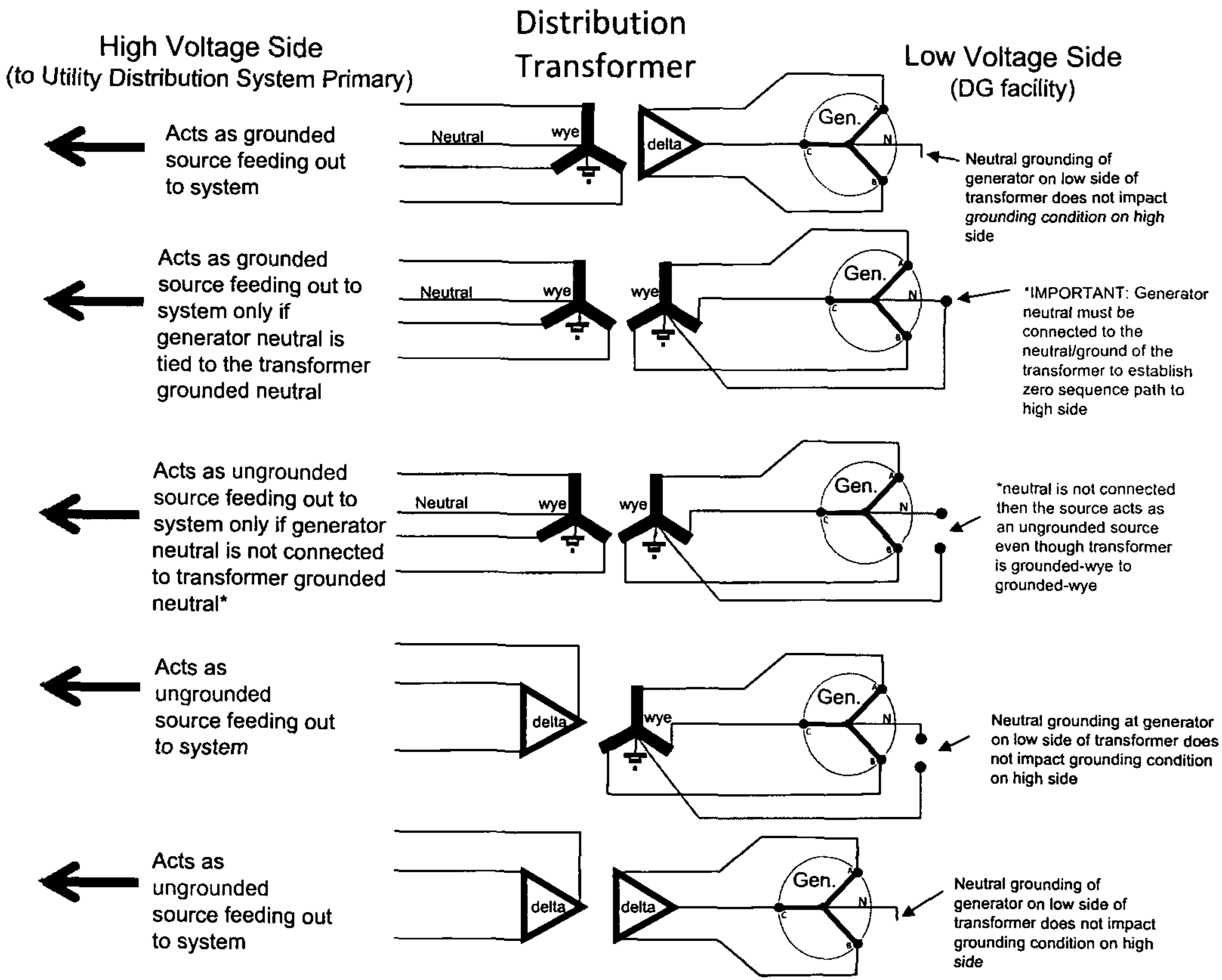
High Voltage Side
(to Utility Distribution System Primary)
Distribution
Transformer
Low Voltage Side
(DG facility)
Acts as grounded source feeding out to system
Neutral
wye
delta
Gen.
A
N
C
B
Neutral grounding of generator on low side of transformer does not impact grounding condition on high side
Acts as grounded source feeding out to system only if generator neutral is tied to the transformer grounded neutral
Neutral
wye
wye
Gen.
*IMPORTANT: Generator neutral must be connected to the neutral/ground of the transformer to establish zero sequence path to high side
Acts as ungrounded source feeding out to system only if generator neutral is not connected to transformer grounded neutral*
Neutral
wye
wye
Gen.
*neutral is not connected then the source acts as an ungrounded source even though transformer is grounded-wye to grounded-wye
Acts as ungrounded source feeding out to system
delta
wye
Gen.
Neutral grounding at generator on low side of transformer does not impact grounding condition on high side
Acts as ungrounded source feeding out to system
delta
delta
Gen.
Neutral grounding of generator on low side of transformer does not impact grounding condition on high side

Ground Fault Overvoltage

- Ungrounded neutral and non-effectively grounded neutral generation sources feeding into 4-wire multigrounded neutral distribution systems can cause potentially damaging ground fault overvoltage on the unfaulted phases under certain conditions!
- What are the conditions needed to cause significant and potentially damaging overvoltage?

1. Generator neutral is not effectively grounded or is ungrounded
2. The actual load at the time of event on the line section impacted is less than 5 times the aggregate generator rating on that section (it is okay to use 3X load ratio as a limit in some cases where generator has higher impedance such as PV).
3. A ground fault is present on the affected section of the feeder and the feeder breaker opens so that there is islanded operation of the DG on the feeder section for at least 1/2 cycle or longer without the substation ground-source transformer bank present

Methods to Suppress and/or Avoid Ground Fault Overvoltage

- Solutions available (any of these alone or in combination can work):
  - Effectively ground **all DG** connecting to the feeder (realize that too much effectively grounded DG can confuse or upset feeder relaying)
  - If DG is not effectively grounded make sure to maintain an **actual load** to generation ratio of at least 5 or more (a ratio of 3 or more can usually work with PV)
  - Don't separate the feeder from the substation grounding source transformer until all non-effectively grounded DG has been "cleared" from the feeder – use a time coordinated DTT or other time coordinated tripping method.
  - Add small grounding transformer banks at strategic point(s) on feeder as needed in locations where they can't be separated from the feeder by operation of the feeder breaker or other device

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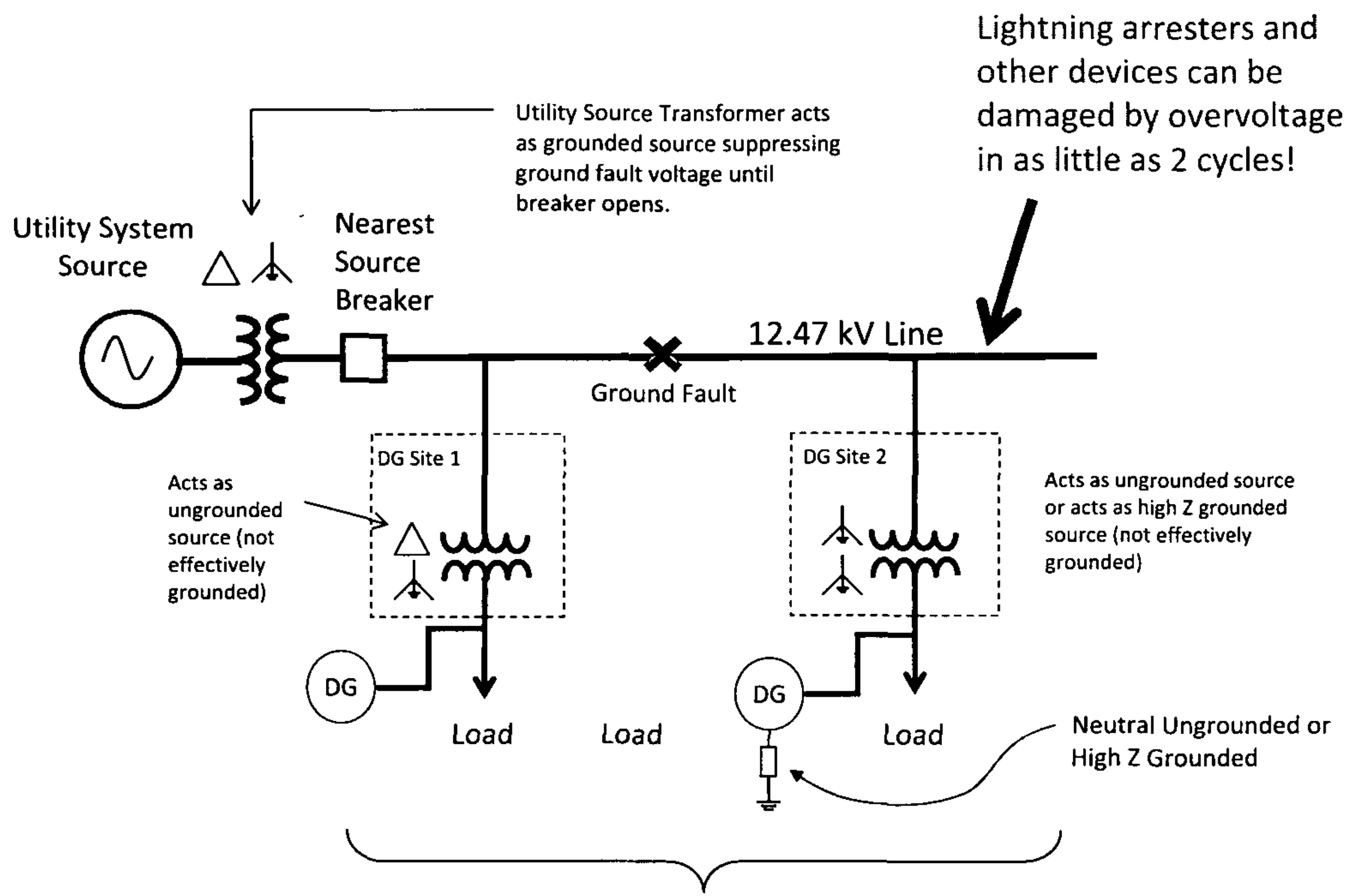

Total load at time of ground fault (taking into account the response of loads due to voltage sags) needs to generally be at least 3 times for PV and in some cases 4 or 5 times the aggregate rating of DG for rotating machines in order to suppress ground fault overvoltage. The amount of load needed depends on the impedance of the DG source and its transformer.

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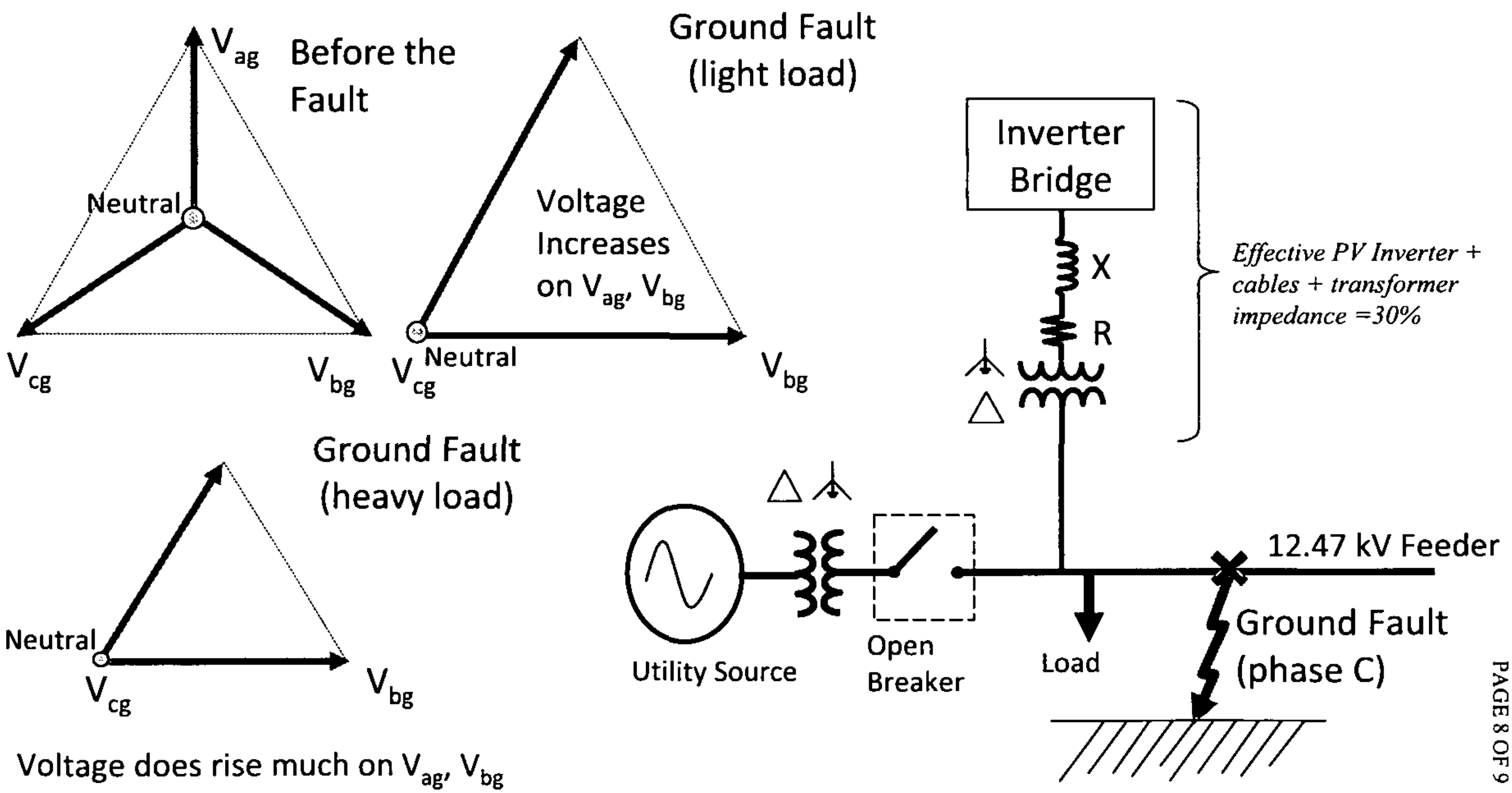
How Load Reduces Ground Fault Overvoltage



Nova Energy Specialists, LLC Contact: Phil Barker Phone (518) 346-9770 pbarker@nycap.rr.com

Conclusions

- Utilities must carefully examine inverter and rotating machine neutral grounding arrangements used in DG installations. Engineers and PV system integrators must be more aware of the grounding issues buried within the inverter architecture – in particular I'm referring to the internal inverter isolation transformer neutral and the way it is connected to the system.
- Commonly used 3-phase inverter neutral connection methods make it difficult to effectively ground PV systems with respect to the utility primary feeder when the distribution transformer is grounded-wye to grounded-wye
- Ungrounded or high impedance grounded PV can still be okay for the power system as long as the criteria (discussed earlier) is satisfied to mitigate over-voltages when needed.

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BP-HECO-IR-31

Ref: HECO Q&I Report

The HECO Q&I Report (i) states that "it is anticipated that the IO [Independent Observer] will be providing an independent report to the Commission regarding his findings, determinations and recommendations for further action with regard to the program's queuing and interconnection procedures after review of the information requests, responses thereto and comments to be received on February 11, 18 and 22, respectively[,]" and (ii) contains a section titled, "Overview of the Proposed Queuing Process for Tiers 1 and 2." *See id.* at 4; Attachment A at 6-10. Please discuss and explain at what point in time in this proceeding the HECO Companies intend to submit formal and final queuing procedures, including the application form and other relevant documents, for review by all parties and approval by the Commission.

HECO Companies Response:

HECO's proposed queuing and interconnection procedures filed February 1, 2010, have been submitted for review and comment to all the parties in this docket. In parallel to HECO's proposal, Zero Emissions Leasing LLC and Clean Energy Maui LLC ("ZEL/CEM") jointly submitted their own proposed queuing and interconnection procedures for the parties to review and comment upon. HECO intends to review the information available including ZEL/CEM's proposal, discuss possible revisions or clarifications with the Independent Observer, and may submit revised or clarified queuing and interconnection procedures either before and/or after the Independent Observer files his report to the Commission.

BP-HECO-IR-32

Ref: HECO Q&I Report

The HECO Q&I Report states, "For all completed Application Packages, Hawaiian Electric will assess each project relative to its potential impact on system reliability[.] ... The IO [Independent Observer] will review the determinations made by HECO before the Applicant is notified of the results." *Id.*, Attachment A at 9.

a. Please discuss and explain whether and to what extent the foregoing assessment is or is not necessary or appropriate, assuming the Commission adopts formal reliability standards in this proceeding, such as the reliability standards proposed by the HECO Companies in the HECO RS Report, that seek to establish a limit on the amount of additional renewable energy that can be incorporated into island grid systems.

b. Please discuss and explain any and all bases, including technical expertise and/or documents and information, upon which the HECO Companies expect the IO to base its review and evaluation of the above-referenced determination by the HECO Companies.

HECO Companies Response:

a. The completeness review of the application materials is intended to confirm the technical information submitted by each applicant to ensure it is consistent and compliant with the reliability standards approved by the Commission.

b. The Company will rely on the information submitted by the applicant, and supplemental information that may also be requested, and any other relevant documents or information sources available to the review team. The Independent Observer will also provide oversight of HECO's review.

BP-HECO-IR-33

Ref: HECO Q&I Report

The HECO Q&I Report states (i) that the HECO Companies will consult with the IO to "assess if any changes or revisions to the [queuing] procedures are appropriate[,]" and (ii) that "In consultation with the IO, Hawaiian Electric will reserve the right to impose additional rules or procedures as necessary to ensure that the FIT program is proceeding in accordance with the Commission's orders." *Id.*, Attachment A at 12; Attachment A at 11. Please discuss and explain whether and to what extent the HECO Companies intend to seek formal Commission approval, in the FIT docket or in any other proceeding, of any such changes, revisions, and/or additional rules or procedures regarding the queuing procedures.

HECO Companies Response:

To the extent appropriate, HECO anticipates that proposed changes to the queuing procedures will be submitted to the Commission for approval.

BP-HECO-IR-34
Ref: HECO Q&I Report
The HECO Q&I Report states, "The Applicant is required to pay the estimated cost of the study [Interconnection Requirements Study ("IRS")] prior to initiation of the study." *Id.*, Attachment A at 9. Please discuss and explain the basis and rationale for requiring full IRS payment prior to initiation of the IRS, including whether and to what extent this requirement does or does not constitute a potential impediment to the FIT, as opposed to payment by initial deposit and installments.

HECO Companies Response:

The costs for HECO to conduct the internal interconnection assessment are not charged to the applicant. Under existing practice, the applicants submit an upfront deposit for the full amount of the estimated cost of the external study. This approach reduces the risks of non-payment to the Company as well as avoids additional administrative expenses that would be associated with requesting and monitoring installment payments. HECO will offer to meet with any applicant to discuss the scope and cost estimate of the interconnection study if requested.

BP-HECO-IR-35

Ref: HECO Q&I Report

The HECO Q&I Report state that "Applicants will already have been required to acknowledge acceptance of the Schedule FIT Agreement as a part of the application submittal process. Projects in the queue which do not require an IRS will have ten (10) business days from the date of notification that they are in the queue to execute the Schedule FIT Agreement." *Id.*, Attachment A at 11 (emphasis added). Please discuss and explain the HECO Companies' position regarding the difference and legal significance, if any, between acknowledging acceptance of the Schedule FIT Agreement as part of the application submittal process and executing the Schedule FIT Agreement.

HECO Companies Response:

The intent of the referenced statement is that the Applicant acknowledges and understands, via electronic acceptance, the terms of the Schedule FIT Agreement during the application submittal process. The Schedule FIT Agreement would not be binding until executed via signature by both parties. The executed Agreement will also serve as the formal notice to proceed to the applicant.

Response to

Division of Consumer Advocacy's

Information Requests

CA/HECO-IR-1

Ref: February 1, 2010 Transmittal Filing, page 3, Note 1.

Hawaiian Electric Company, Inc. ('HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Ltd. ("MECO") (collectively, "the HECO Companies'") state, in relevant part, that the Feed-in Tariff ('FIT") Program queue system will operate in parallel with other energy contracting mechanisms, including, but not limited to, negotiated power purchase agreements ("PPAs") and competitive bidding. According to the HECO Companies, the February 1, 2010 Transmittal Filing "pertains specifically to the FIT Program" and that "in developing the proposed FIT queuing procedures, the [HECO] Companies are mindful of [the FIT queuing procedure's] potential applicability to other energy contracting mechanisms and the importance of establishing an overall energy procurement framework that is fair and transparent to all projects, regardless of contract type."

a. Please discuss whether the FIT queuing procedures should be reviewed, analyzed, and considered as a "stand-alone" proposal or with respect to, or in the context of, the other energy contracting mechanisms available to the HECO Companies, such as negotiated PPAs and the Competitive Bidding Framework.
   1. If the HECO Companies believe that the FIT queuing procedures should be reviewed, analyzed, and considered as a "stand-alone" proposal without regard to the other energy contracting mechanisms available to the HECO Companies, please explain why the HECO Companies reach that conclusion.

b. Please explain how the HECO Companies envision the FIT queuing procedures fitting into the broader array of energy procurement mechanisms that the HECO Companies use to meet their obligations to serve their customers safely and reliably. In answering the information request, please discuss how the FIT queuing procedures will work if the HECO Companies also have viable energy projects (delivery of energy to the HECO, HELCO, or MECO grids) available through a negotiated PPA and/or the Competitive Bidding Framework.

c. Assuming that, as presently configured and with the existing amount generating resources available, the HECO Companies can only accept a finite amount of energy onto their respective systems, how should the FIT queue be viewed with respect to the HECO Companies other energy procurement mechanisms?

d. Assuming that, as presently configured and with the existing amount generating resources available, the HECO Companies can only accept a finite amount of energy onto their respective systems, how should the FIT queue be viewed if the HECO Companies have viable options available under different procurement mechanisms, assuming further that each viable option can provide energy to the HECO, HELCO, or MECO grid within similar timeframes?

<u>HECO Companies Response:</u>

a. As stated in HECO's transmittal letter dated February 1, 2010, the queuing procedures in the Merrimack Report were developed specifically for the FIT program, and more specifically, for the FIT Tier 1 and 2 level projects.

b. The queuing procedures developed by HECO for the FIT program have attempted to focus on identifying projects that are the most viable and providing them an opportunity to successfully contract with HECO and get their projects expeditiously installed and completed. These same concepts of identifying the most viable projects are also inherent in a competitive bidding process. Because the FIT program and the competitive bidding framework each target different sized projects, the programs complement each other in this regard. The bilateral negotiations are eventually envisioned to apply primarily to those projects that are otherwise not able to fit into HECO's established contracting mechanisms.

c. The FIT program provides an additional and complementary option to HECO's existing and future renewable resource procurement mechanisms. Decisions will have to be made in establishing what order and priority will be applied by HECO to the various contracting mechanisms. Those discussions are currently in progress both internally and with the Independent Observer. Additionally, the proposed Reliability Standards Working Group should consider this from a policy perspective.

d. HECO concurs with the Consumer Advocate's observation that with limited capacity available for projects, decisions will have to be made in establishing what order and priority will be applied by HECO to the various contracting mechanisms. Those discussions are currently in progress both internally and with the Independent Observer. Additionally, the proposed Reliability Standards Working Group should consider this from a policy perspective.

CA/HECO-IR-2

Ref: Attachment A, February 1, 2010 Transmittal Filing, page 9 (Queuing Procedure).

a. For all completed FIT Application Packages, the HECO Companies will assess, among other things, each FIT project relative to the project's impact upon system reliability, the ability of the project to interconnect to the system in an expeditious manner, and the availability of sufficient distribution or transmission capacity to connect the project to the HECO Companies' systems. Please confirm that this means that each project must pass an initial review before the project is eligible to be placed in the FIT queue.

b. If FIT Application Packages must pass an initial review before a project will be eligible to be placed in the FIT queue, what order will FIT Application Packages be reviewed?
   1. On a "first come, first served" basis, regardless of whether the FIT Application Package is complete or not?
   2. By the date (and if need be, time) by which the FIT Application Package is deemed complete?
      (a) If so, who deems a FIT Application Package to be complete?
         (1) The HECO Companies in their sole discretion?
         (2) The HECO Companies, following consultation with the Independent Observer?
         (3) The Independent Observer, following consultation with the HECO Companies?
         (4) The Independent Observer in his or her sole discretion?
         (5) Some other configuration involving both the HECO Companies and the Independent Observer?
         (6) By following a checklist posted on FIT Application website?
   3. By some other ordering method?
      (a) If so, please describe the method.
      (b) Why was that method selected?

c. Please confirm whether it is possible that the order in which FIT Application Packages are reviewed could have impacts on the subsequent review of other, later submitted and/or reviewed, FIT Application Packages.
   1. If there could be impacts on the review of other, later submitted and/or reviewed, FIT Application Packages, could the order of initial review referenced in part (b) of this information request be important to FIT subscribers (i.e., project developers)?

d. Does the tier in which a FIT Application Package fall – either Tier 1, 2, or 3 – make a difference in the order in which a FIT Application Package is reviewed?
   1. If the answer is "yes," please explain why the treatment is different for FIT Application Packages in Tiers 1, 2, and 3.

e. Please explain what the HECO Companies mean when it says "the ability of [a] project to interconnect to the system in an expeditious manner."

<u>HECO Companies Response:</u>

a. The HECO Companies confirm that each project must pass an initial review before the project is eligible to be placed in the FIT queue.

b. The FIT application packages will be reviewed by the date (and if need be, time) by which the application is deemed complete. The completeness review will be performed by the HECO Companies under the oversight of the Independent Observer.

c. The order of the review of the application packages for completeness will not be affected, but the order that the projects are evaluated for interconnection may be. Once the applications are deemed complete, the interconnection requirements assessment will then be conducted on the basis of date/time stamp of the submittal of the application. The space available on a particular distribution circuit could be affected if multiple projects are proposing to interconnect to the same circuit. In other words, a complete project application package with an earlier date/time will have priority on a given circuit before a complete project application package with a later date/time stamp.

d. No. Since the queue capacities for the different Tiers will be made available through a staggered release, overlap of application reviews should be minimized.

e. A project that has the ability to interconnect to the system in an expeditious manner is anticipated to be a project that does not trigger additional technical interconnection studies.

CA/HECO-IR-3
Reference: p. 9.

a. Please explain how the HECO Companies envision the FIT queuing procedures working with respect to Tiers 1, 2, and 3 of the FIT Program. In answering the information request, please discuss how the FIT queuing procedures will work if the HECO Companies have viable energy projects (delivery of energy to the HECO, HELCO, or MECO grids) available through Tiers 1, 2, and 3 of the FIT Program in the same circuit or geographic location.

b. Assuming that, as presently configured and with the existing amount of generating resources available, the HECO Companies can only accept a finite amount of energy onto their respective systems, how should the FIT queue be viewed with respect to Tiers 1, 2, and 3 of the FIT Program?

c. Assuming that, as presently configured and with the existing amount of generating resources available, the HECO Companies can only accept a finite amount of energy onto their respective systems, how should the FIT queue be viewed if the HECO Companies have viable options available Tiers 1, 2, and 3 of the FIT Program, assuming further that each viable option can provide energy to the HECO, HELCO, or MECO grid with similar timeframes?

HECO Companies Response:

a. The HECO Companies agree with the Independent Observer's proposal for a phased implementation schedule for the initial release of the FIT program. An initial increment of Tier 1 capacity will be released first, followed by Tier 2 and Tier 3. This phased approach will allow for initial allocation of circuit capacity to the smaller tiers first, however, subsequent releases of Tier capacity would not necessarily be performed in the same order.

b. In a situation where there is limited capacity available for FIT resources, the allocation of queue capacity between the various Tiers is intended to be done in such a manner that takes into account applicant demand for each tier level as well as system impacts associated with the different tier levels. Additionally, the proposed Reliability Standards Working Group should consider this from a policy perspective.

c. See b. above.

CA/HECO–IR-4

Reference: February 1, 2010 Transmittal Filing.

a. Please provide a detailed comprehensive list of items that must be provided in order for an application to be deemed complete.
   1. If the Company anticipates having a different checklist for each tier, please provide each checklist as applicable.
   2. If not evident, please discuss the effect, if any, that the different checklists might have on the queuing order.

b. Please discuss whether the companies will be developing standardized forms to be attached to the application checklist or from to establish homogenous forms to expedite the review process, as compared to allowing different forms to be used, which might require additional time to gather the necessary information from those not-standardized forms.

c. If not already discussed, please provide a detailed discussion of the intake process and the "public" viewing access to determine the status of the application review, determination of completeness and queuing order.

HECO Companies Response:

a) The application checklist is still under development in consultation with the Independent Observer. Once a review draft is ready, the parties will be allowed an opportunity to provide feedback. There is a possibility that the Tier 3 information requirements and associated application checklist may be different from that for Tier 1 and 2 applications.

b) The Company's preference is to develop standardized application forms to facilitate the review process.

c) The Independent Observer will be responsible for posting the queue on the HECO FIT website. Please refer to the Queuing Procedures section on page 8 of the Merrimack Report for a more detailed description of the proposed Queuing and Interconnection Procedures.

CA/HECO–IR-5
Reference: Attachment A, February 1, 2010 Transmittal Filing.

a. The company indicates that the proposed queuing process for Tiers 1 and 2 is illustrated in Figure 1. Please discuss whether the Company expects or proposes to use a different process for Tier 3 applications, when developed. If so, please identify the anticipated differences.

b. For each of the differences, please explain why that difference is required.

HECO Companies Response:

a. As noted in the January 2010 workshop, the queuing process for Tier 3 projects is still under discussion and development with the Independent Observer. The parties generally agreed at that time with the guidance provided by the Commission to focus on Tier 1 and 2 first. A workshop is being planned for early March to begin soliciting feedback from the parties on Tier 3 issues.

b. Due to the expected higher levels of project development risks for the Tier 3 sized projects, it may be appropriate to request additional information from project applicants that are not necessary for smaller Tier 1 and 2 projects (i.e. environmental permits, land use approvals, etc.). If appropriate, this information may be used to conduct assessments to rank projects for the queue.

CA/HECO–IR-6

Reference: Attachment A, February 1, 2010 Transmittal Filing.

a. Based on the Company's Figure 1, it appears that applications requiring an interconnection study will not be considered as complete for queuing purposed until the applicant pays for the study and the study has been completed. Please confirm this understanding.
   1. If not, please provide the necessary corrections to this understanding.

b. Please describe the IRS process and how the studies will be completed.
   1. If not already discussed, please confirm that each interconnections study will be conducted on a 'first-in, first-out" basis that is based on the order of receipt, regardless of procurement mechanism.
   2. If not, please discuss how the order to perform and complete interconnection studies will be determined.

c. If not already discussed, please discuss whether it is generally reasonable to expect different review times for interconnections studies depending on the project size. For instance, will a Tier 3 IRSO generally take longer than a Tier 2 IRS? Please explain.

d. It there are expected differences in the times required to conduct IRS for different tiers, please discuss the advantages and disadvantages to prioritizing studies and applications expected to take less time to complete.

HECO Companies Response:

a. The requirement for an IRS does not have an impact on whether or not an application is complete for queuing purposes. As part of the completeness assessment HECO will determine if an IRS is required. An application can be considered complete and still require an IRS. If an IRS is required, the applicant can decide whether to pay for and proceed with the IRS or withdraw from the process.

b. The process for determining the prioritization of IRS work across the various contracting mechanisms is still under discussion at HECO. In general, the first in first out concept will likely be the prevailing practice. However, there should also be some consideration to provide for the less complex studies to be allowed to proceed toward completion, even if they come in after a more complex project, so that those projects can be installed sooner.

c. Differences in review times for interconnection studies may be affected by project complexity, size, as well as project location and performance characteristics of the project.

d. Projects with less complex interconnection studies would be expected to be prioritized since they would be expected to be able to be completed in less time.

CA/HECO–IR-7
Reference: Attachment A, February 1, 2010 Transmittal Filing.

a. Please confirm that any application that requires an IRS will be placed on "hold" until the study is complete and that, until the IRS is completed, that application will not be placed in the queue.

b. Assume that, at the time of the application, the completeness checklist is met, but during the course of the project, the status of one or more items changes such that the application might no longer be deemed complete. Please discuss whether there is any grace period for correction of the item(s) that changed and what impact, if any, that has on the queuing order.

HECO Companies Response:

a. For projects that trigger an IRS, those projects will be held from the queue until the applicant authorizes the study to proceed by signing the interconnection agreement and paying the deposit for the study. If at any time through the end of the IRS the applicant elects not to proceed, the project will be removed from the queue.

b. There is currently no specific provision for a grace period, but if the circumstances that resulted in such a change in status were deemed truly unforeseeable, a grace period could be considered subject to the concurrence of the IO.

CA/HECO-IR-8

Ref: February 8, 2010 Transmittal Filing, page 2.

The HECO Companies state, in relevant part, as follows:

> . . . in developing . . . reliability standards, the [HECO] Companies endeavored to develop standards which would[] (1) define the circumstances in which [feed-in tariff ('FIT")] projects can and cannot be incorporated on each island without markedly increasing curtailment, either for existing or new renewable [energy] projects; (2) allow . . . utilities to maintain system reliability; (3) avoid unreasonable costs to ratepayers; and (4) allow a developer . . . to be able to gauge the probability that its project could be developed on a particular grid system.

a. Please explain whether, given the current state of the HECO Companies generation, transmission, and distribution infrastructure, and the existing state of energy production, transmission, and distribution technology available on the relevant markets, the HECO Companies, in general, agree with the following statement: "The peak customer load - whether it be the system peak or the daily peak – on any given island at any given time represents, irrespective of generation source (in other words, ignoring the means by which customer load will be met), the maximum amount of energy (i.e., electricity) that the HECO Companies require to meet its obligation to serve all customers."

b. Please explain whether, given the current state of the HECO Companies generation, transmission, and distribution infrastructure, and the existing state of energy production, transmission, and distribution technology available on the relevant markets, the peak customer load – whether it be the system peak or the daily peak – also represents the maximum amount of energy (i.e., electricity) that the HECO Companies can accept onto its constituent systems (i.e., the HECO, HELCO, or MECO grids) at any given time.

c. Please explain why the HECO Companies believe that the Companies' Load Forecast and/or Adequacy of Supply Report analyzed in conjunction with the Companies' Capacity Planning Criteria is insufficient to:

> (1) define the circumstances in which FIT projects can and cannot be incorporated on each island without markedly increasing curtailment, either for existing or new renewable [energy] projects; (2) allow the utilities to maintain system reliability; (3) avoid unreasonable costs to ratepayers; and (4) allow a developer . . . to be able to gauge the probability that its project could be developed on a particular grid system.

d. Please discuss whether (I) the FIT queuing procedures, (II) queuing procedures in general, and/or (III) curtailment order would be more important than the reliability standards in (1) defining the circumstances in which FIT projects can and cannot be incorporated on each island without markedly increasing curtailment, either for existing or new renewable energy projects and (2) allowing a developer to be able to gauge the probability that its project could be developed on a particular grid system.

<u>HECO Companies Response:</u>

a. Stated another way, HECO understands it is being asked whether it agrees with the statement: "The maximum amount of energy the utility must deliver to its customers in order to satisfy the utility's obligation to serve is the peak amount that customers need." HECO does not agree with this statement.

The "obligation to serve" arises out of understanding the rights and obligations of utilities and their customers. The "regulatory compact," as stated by this Commission, "has two aspects: (1) in return for monopoly franchise, utilities accept the obligation to serve all comers; and (2) in return for agreeing to commit capital necessary to allow utilities to meet the obligation, utilities are assured a fair opportunity to earn a reasonable return on the capital prudently committed to the business." In re: Citizens Utilities Company, Kauai Electric Division, Docket No. 94-0097 and Docket No. 94-0038 (Consolidated), Decision and Order No. 14859 at 13 (filed August 7, 1996).

In Docket No. 2009-0108 (Proceeding to Investigate Proposed Amendments to the Framework for Integrated Resource Planning), HECO stated, "Specifically, the utility has the responsibility and obligation, among others, to: (1) ensure that there is an adequate supply of generation, (2) provide reliable service, (3) comply with RPS law, and (4) comply with State and possibly federal GHG regulation." [Final Statement of Position of the Hawaiian Electric Companies, dated December 21, 2009, page 14]

Satisfying the utility's obligation to serve goes beyond simply providing energy to meet customers' demand at given moments in time. The supply of generation must be sufficiently large to meet all reasonably expected demands for service and provide reasonable reserves for emergencies. The HECO Companies need to consider many different factors, such as present and future demand for electricity, planned outages of generating units, the likelihood of unexpected outages of generating units, the potential for actual demand to exceed forecasts, and the long lead times that it takes to permit and install new firm generating capacity. If the HECO Companies do not have a sufficient amount of electric generating capability to account for contingencies such as generating unit failures or demand for electricity being greater than forecast, then if these contingencies occur, the HECO Companies will not be able to provide electric service to some customers.

Furthermore, in association with the utilities' obligation to serve, the provision of electric service must meet the standards set forth in the Commission's General Order No. 7 (Standards for Electric Utility Service in the State of Hawaii) ("G.O. 7"). Part VII of G.O. 7 sets standards for quality of service.

b. Stated more simply, HECO understands the question to be whether the peak customer demand represents the maximum amount of energy that a particular system can accept at any given time. HECO's response is, no, the peak customer demand does not represent the maximum amount of energy that a particular system can accept at any given time. The correct statement is that the customer demand at any given time represents the maximum amount of power that a particular system can accept at that time.

First, a distinction must be made between <u>power</u> (or instantaneous <u>load</u> or demand), which is measured in kilowatts ("kW"), and <u>energy</u>, which is the amount of power delivered over a period of time and which is measured in kilowatt-hours ("kWh"). Peak customer load (or demand) is the instantaneous <u>rate</u> at which energy is delivered. Given this distinction, HECO understands the restated question to be whether the peak customer demand represents the maximum amount of power that a particular system can accept at any given time.

Second, in order to maintain a constant frequency of 60 cycles per second (Hertz or

Hz) on the system, supply (generation) and demand (customer load) must be equal at all times. If supply exceeds demand, then system frequency will rise. If system frequency rises too high, then generation could trip off line due to overfrequency. If demand exceeds supply, the system frequency will fall. If system frequency falls too low, customer load could be shed from the system due to underfrequency. The tripping of generation off line or the shedding of customers from the system are measures designed to restore frequency to 60 Hz and to protect the system from serious damage.

To illustrate why peak customer demand does not represent the maximum amount of power that a particular system can accept at any given time, consider that the maximum demand on the HECO system in 2009 was 1,213 MW-net, which was recorded on Wednesday, October 7, 2009. This peak demand of 1,213 MW-net does not represent the maximum amount of energy that the HECO system can accept at any given time, other than the time at which this peak demand occurred. At every other hour in the year, demand was less than 1,213 MW-net. This means that the maximum amount of power the system could accept at every other hour in the year was less than 1,213 MW-net. For example, at some given early morning hour, the total demand on the system was 600 MW-net. This means that the maximum amount of power the system could accept in this hour was 600 MW-net. If more than 600 MW-net was delivered in this hour, the system frequency would have exceeded 60 Hz.

c. Each HECO Company's capacity planning criteria are used to in the Adequacy of Supply ("AOS") Reports to assess the adequacy of each specific company's supply (generation) to meet expected demand. The AOS reports do not evaluate the adequacy of each company's transmission and distribution systems to meet regional or local demand under expected or contingency (line outages) situations. In order to determine whether or not FIT projects can be integrated into the system at specific locations, line currents and area voltages must be evaluated under expected and contingency situations. This work is not conducted with the scope of the Adequacy of Supply assessments, which focus only on the generating system. Rather, the impacts of FIT projects must be evaluated in Interconnection Requirements Studies.

d) It is difficult to say that any one of the listed components is "more important" than any other. The components work together to provide a transparent process for developers to be able to evaluate how a proposed project may be able to be integrated onto a particular grid at a particular point in time. FIT queuing procedures and queuing procedures in general are intended to provide a fair and transparent process for developers to understand where they stand versus other projects in a particular queue given the time and completeness of application, complexity of interconnection and ability to meet established project milestones. To the extent that curtailment of a FIT resource would be necessary, curtailment order is meant to provide a developer with notice of the order in which the developer's project may be curtailed versus other curtailable resources on a particular system or circuit. As discussed in the Hawaiian Electric Companies' Report on Reliability Standards filed on February 8, 2010, a goal of the system studies conducted by the Companies was to determine, pursuant to the directives of the Commission's September 25, 2009 Decision and Order, an appropriate level of FIT resources which could be accepted on a particular system without markedly increasing curtailment either for existing or new renewable projects.

CA/HECO-IR-9

Ref: February 8, 2010 Transmittal Filing, page 2 through 3.
The HECO Companies state, in relevant part, that:

> . . . [d]uring the development of . . . reliability standards, there were discussions, both internal and with stakeholders, regarding whether reliability standards such as those adopted by the North American Electric Reliability Corporation ("NERC") for the Bulk Electric Systems of North America would be sufficient. It was determined, consistent with the Commission's recognition that "*simple metrics might not fully capture reliability considerations*," that more was needed in order to comply with the directives noted above. (Decision and Order at 50.) Specifically, simple metrics would not necessarily allow a developer to be able to gauge the probability that its proposed project could be interconnected to a particular grid system (i.e., that there is "room" on a particular system) absent a project specific evaluation against all of the reliability criteria.
> (Footnotes omitted.)

a. Please explain how the HECO Companies' Capacity Planning Criteria is conceptually different from those reliability standards issued and/or approved by NERC.

b. Please explain why the HECO Companies believe that the Companies' Load Forecast and/or Adequacy of Supply Report analyzed in conjunction with the Companies' Capacity Planning Criteria is insufficient to gauge, in a rough sense, whether a "proposed project could be interconnected to a particular grid system (i.e., that there is "room" on a particular system) absent a project specific evaluation . . . ."

HECO Companies Response:

a. Attached are the capacity planning criteria for Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Limited ("MECO") for the Maui, Lanai and Molokai Divisions (collectively referred to as the "HECO Companies").

The HECO Companies' capacity planning criteria apply only to the generating systems of each company. The capacity planning criteria are used to determine the adequacy of the amount of generating capacity to meet expected demand while allowing for certain contingencies, such as the unexpected outage of generating units while other units are unavailable due to maintenance. The criteria do not apply to the transmission and distribution systems or to operations. In contrast, the NERC reliability standards apply to a far greater scope. For example, the NERC reliability standards cover a wide range of topics including, resource and demand balancing; communications; critical infrastructure protection; emergency preparedness and operations; facilities design, connections and maintenance; interchange scheduling and coordination; interconnection reliability operations and coordination; modeling data and analysis; nuclear; personnel performance, training and qualifications; protection and control; transmission operations; transmission planning; and voltage and reactive. The complete NERC reliability standards can be found at www.nerc.com.

b. The load forecasts prepared by HECO, MECO and HELCO are for total system demand. The forecasts do not include breakdowns for regional, local or individual circuit loads. The amount of "room" on a system is not necessarily an indication of the amount of "room" available in every region, locality or circuit because the amount of remaining capacity in each area is not uniform throughout the system. It would depend on the load in the area and the capacity of the grid in that area. One area may be near capacity at the transmission or distribution level while there may be ample capacity in another. On average, there may appear to be sufficient room, but there may not be sufficient room in localized areas. Thus, project-specific evaluations that take into account localized conditions must be performed to determine whether a proposed project can be interconnected to the grid at a specified location.

With respect to the capacity planning criteria, as stated in response to part a. above, the criteria are applied only to the generating system. HECO, HELCO and MECO submit to the Commission each year reports that assess the adequacy of supply to meet expected demand for each system based on the application of each system's specific capacity planning criteria. The criteria do not apply to the transmission and distribution systems. There are separate transmission and distribution planning criteria. Therefore, the capacity planning criteria alone are not sufficient to determine whether or not a proposed project could be interconnected to a particular system at a specified location.

Response to

Department of Business, Economic Development, and Tourism's

Information Requests

DBEDT/HECO-IR-1

Ref.: Page 7.

a) Please provide the workpapers used in the determination of the Tier 1 and Tier 2 application fees and the refundable Tier 2 reservation deposit.

b) Please explain how HECO determined or assessed that a proposed application fee of $200 for Tier 1 and $10/kW up to $1,000 for Tier 2 are the appropriate fees to discourage frivolous projects while not creating a barrier to entry for smaller developers. Please provide the supporting analysis and workpapers.

c) Please indicate whether or not the refundable reservation deposit will include interest and the applicable interest rate. If it is not, please explain why not.

HECO Companies Response:

a) Please refer to the Merrimack Report, Exhibit 1 of Attachment A.

b) HECO reviewed the application fees and reservation deposits included in other FIT programs identified in the Merrimack Report, Exhibit 1 of Attachment A, as well as discussions with the Sustainability Priced Energy Development (SPEED) Facilitator in Vermont. For example, Vermont has an administrative fee of $200 while the application fee for Ontario ranges from $500 to $5,000. HECO sought input on appropriate fee amounts from the parties at the November 2009 workshop, but none was offered. DBEDT did raise a concern that the fee should not be set too high to discourage individual residential type applicants. HECO felt it was important to set the fee at an amount to discourage frivolous projects consistent with the Commission's order, but like DBEDT, did not want the fee to be seen as a barrier to applicants, in particular, the residential applicant. After consultation with the Independent Observer, the fee structure shown in the Merrimack Report was agreed upon as a reasonable amount to address both concerns.

c) HECO's proposed queuing procedures do not include payment for interest associated with the refundable reservation deposit. The requirement for the refundable reservation deposit is intended to serve as an encouragement for applicants to work diligently to complete their project in a timely manner or similarly, make a timely decision to terminate their project rather than occupy space in the queue that could be utilized by other projects.

DBEDT/HECO-IR-2

Ref.: Page 6-8.

a) Please specify all the required information and documents in addition to the Application Form for a complete application submittal.

b) Please explain how projects will be selected for the queue and offered a Schedule FiT Agreement.

c) Please indicate the timeline (i.e., how long) after submission of a completed application and when a project is selected for a queue and offered a Schedule FiT Agreement.

d) Please indicate the timeline (i.e., how long) for the HECO Companies to complete the project assessments indicated under "Queuing Procedure" on page 8 after receipt of the completed "Application Package" from the applicant.

HECO Companies Response:

a) The required information and documents in addition to the Application Form that will be required for a complete application will be developed in conjunction with further discussions with the Independent Observer.

b) Please refer to the Merrimack Report, Queuing Procedures, on page 8. The proposed assessment criteria are provided.

c) The timeline for a project from submission of an application to offering of a Schedule FIT Agreement will be dependent on the number of applications received and the FIT tier being used. It is anticipated that Tier 1 and 2 projects will take less time to evaluate then Tier 3. The Independent Observer will monitor HECO's review of the applications to facilitate a timely review process. If the process encounters delays, the Independent Observer will be able to work with the parties to identify the causes of these delays and encourage timely resolution of the problems. The Independent Observer is also able to report directly to the Commission on any problems that may warrant the Commission's attention.

d) The time required to perform the completeness of review of applications will depend on the number of applications received and the FIT tier being used. See also the response to subpart c above.

DBEDT/HECO-IR-3

Ref.: Page 8-10.

a) Please explain how projects will be ranked or assigned a place in the queue.

b) Please indicate the timeline (i.e., how long) for the HECO Companies to complete the interconnection assessment and review process of a project as indicated on pages 8 and 9.

c) Please indicate the timeline (i.e., how long) for the HECO Companies to complete an IRS and provide the results to the applicant.

d) Please provide the steps for interconnecting a project to the grid.

e) What are the timelines and milestones that a project must achieve to maintain its place in the queue, or stay in the queue?

f) Please describe Hawaiian Electric's mechanisms or conditions for applicants to apply for extensions for the amount of time needed to meet project development milestones prior to dropping from the queue.

g) Will the amounts of the incremental releases of capacities be subject to Commission approval? If not, why not?

h) Are the proposed "Reliability Team's" reassessment activities subject to the IO oversight? If not, why not?

i) When the incremental capacity releases are filled, will the application be closed to new applicants or will HECO continue to accept applications and place applicants in waiting list? If not, why not?

j) When a project drops out from the queue, how will that project's place in a queue be filled?

k) Please provide a summary of the queuing steps.

l) Please provide a summary of the interconnections steps.

m) Please indicate the HECO Companies' estimate of the timeline from application to interconnection for Tier 1 projects.

n) Please indicate the HECO Companies estimate of the timeline from application to interconnection for Tier 2 projects.

HECO Companies Response:

a) Please refer to HECO's response to DBEDT/HECO-IR-2b.

b) The time required to perform the interconnection assessment and review process for all applications will depend on the number of applications received. The Independent Observer will monitor HECO's assessments to facilitate a timely review process. If the process encounters delays, the Independent Observer will be able to work with the parties to identify the causes of these delays and encourage timely resolution of the problems. The Independent Observer is also able to report directly to the Commission on any problems that may warrant the Commission's attention.

c) A timeline for completion on an IRS is dependent on several factors including the level of complexity of the proposed interconnection and the responsiveness of the applicant in providing the necessary information for the study.

d) Please see the HECO Companies' Rule 14.H.

e) At the November 2009 workshop, HECO sought and received feedback from the parties on identifying project development milestones that would be appropriate to ensure that only viable projects remain in the queue. During subsequent discussions with the Independent Observer, HECO was also encouraged to consider an alternative of setting a maximum amount of time for projects to be completed. This would eliminate the need for the additional administrative steps of monitoring milestones for each project. The Independent Observer received favorable feedback when he raised this approach at the January 2010 workshop. Accordingly, HECO proposes to incorporate this approach in the Schedule FIT Agreement.

f) The procedures for applying for extensions are under development with the Independent Observer.

g) HECO anticipates that once identified, the amount of capacity in the incremental releases will be submitted to the Commission for approval.

h) No. In accordance with the Commissions Decision & Order, the Independent Observer's scope applies to the queuing and interconnection procedures. The scope of work for the Independent Observer's contract was prepared consistent with the Commission's Order and was approved by the Commission on January 28, 2010. As described in the HECO Companies' Response to Commission's Letter of February 19, 2010 filed February 26, 2010, the HECO Companies propose that an Independent Facilitator be retained for the Reliability Standards Working Group.

i) The Independent Observer has recommended allowing applications to be accepted until 110% of the capacity designated for the tier release is filled. The applications in this extra 10% will be designated for the reserve queue.

j) When a project drops from the queue, a project in the reserve queue will be allowed to move up into the queue.

k) Please refer to HECO's response to part a) above.

l) Please refer to HECO's response to part d) above.

m) The overall timeframe from application to completion of a Tier 1 project will be dependent on many factors and is difficult to estimate at this time. During the January 2010 workshop, the parties did provide feedback to the Independent Observer that a timeframe of 12 months was reasonable for completion of Tier 1 projects.

n) The overall timeframe from application to completion of a Tier 2 project will be dependent on many factors and is difficult to estimate at this time. Please see HECO's response to part m) above for a reference for Tier 1 projects. It is anticipated that Tier 2 projects may be similar.

DBEDT/HECO-IR-4

Ref.: Exhibit 1, Pages 2-3.

a) Please explain what "operational measures" means as used in footnote #1.

b) Please provide the "different operational measures" that apply to each of the HECO's island systems (HECO, HELCO, and MECO) as referred to in footnote#1.

c) Please provide the "reliability standards" that HECO developed which "would (1) define the circumstances in which Fit projects can or cannot be incorporated on each island without markedly increasing curtailment, either for existing or renewable projects; (2) allow the utilities to maintain system reliability; (3) avoid unreasonable costs to ratepayers; and (4) allow a developer of a renewable energy project to be able to gauge the probability that its project could be developed on a particular grid system." Please provide the "reliability standards" for each of the four conditions cited.

d) Please provide the "reliability standards" that HECO developed that "complement existing standards, including those in the HEOC Companies' tariff Rule 14H, and should provide greater predictability with respect to reliability issues for developers" as required by the Commission's decision and order.

HECO Companies Response:

a. Operational measures are the operating criteria. Examples are referenced in Table 8 of Exhibit 1 of the HECO Companies Report on Reliability Standards filed February 8, 2010. The footnote references the NERC reliability standards and the core reliability principles used. The Hawaiian Electric Companies currently plan and operate their systems in accordance with reliability principles that are very much aligned with the NERC reliability principles, however the numbers used by the Companies for various measures or criteria and the range for various settings on frequency, voltage, and reserve determination are respective of the unique operational circumstances on each of the island grids.

b. Examples are referenced in Table 8 of Exhibit 1 of the HECO Companies Report on Reliability Standards filed February 8, 2010.

c. As with the NERC Reliability philosophy, the proposed standards including cost, operability, compatibility and reliability to operate through normal and abnormal conditions work in conjunction to ensure system reliability. System operating criteria and actions are aligned to each of the principles and govern the operations of transmission and distribution resources on the system. As shown in Figure 7, utility studies link back to the Reliability Standards and define the flow for analyzing new projects. Depending on the degree of penetration on a circuit and the level of study required on the system based on existing levels of penetration, the performance of the new FIT projects will be assessed in conjunction with the rest of the system for impacts. Before an assessment of whether the FIT project can or cannot be incorporated on the integrated system without markedly increasing curtailment, its performance using the standard interconnection process for reliably connecting to the grid must be met. Depending on where the DG resource is interconnected, different interconnection standards must be met (Rule 19 or Rule 14.H). This provides the developer an initial indication of the probability that a specific project may be able to be developed on a particular grid system. If there is a system impact, additional monitoring such as dedicated SCADA or other control devices may be required. This evaluation will provide developers with an indication of the additional cost factors associated with interconnecting a specific project. The system level studies that may be conducted evaluate the performance and benefits (e.g., dispatchability, availability) of the resource as it impacts the system's normal and abnormal operations modes (e.g. frequency, voltage, transmission and distribution level protection schemes, contingency conditions and associated reserves) and potential for displacement of other existing renewable resources. Utility load flow and dynamic simulation models typically are utilized to assess impacts. Examples of dynamic studies are referenced in Attachment 2 of Exhibit 1 of the HECO Companies Report on Reliability Standards filed February 8, 2010. If adding the resource pushes the system outside of normal operational measures and reasonable and cost-effective measures are not readily applicable to accommodate the resource, then the project may not be cost-effective for ratepayers. Additionally, if the resource causes significant curtailment of other existing renewable resources in order to come online, then the project may also not be recommended for interconnection as it may not be cost-effective for ratepayers to displace one form of renewable for another and such displacement would be inconsistent with the Commission's Decision and Order. Per the Decision and Order, the utilities are required to file a report to the Commission advising them of any such occurrence, and including the analyses supporting these recommendations.

d. Please see the response to subpart c.

DBEDT/HECO-IR-5

Ref.: Exhibit 1, Pages 6-17.

a) Please specify and describe what "targeted studies to address specific system impacts" are required and planned by HELCO to accommodate higher levels of penetration of variable renewable energy generation on the HELCO grid.

b) Please indicate when these studies will commence and how long it will take.

c) Please provide a list of the specific "system issues which negatively impact reliability" that are caused by the "present levels of distributed generation" on the HELCO system. Please provide the data that evidenced their occurrence.

d) Please specify what "reliability standards" that are currently used by HELCO are specifically impacted, and how, by the existing levels of variable renewable generation penetration on the HELCO grid.

e) Please provide all data on the frequency and duration of the curtailments of each of the existing variable renewable generation on the HELCO system for the last three years.

f) Please specify the procedure used by HELCO to curtail each of the existing variable renewable generation due to "system reliability issues".

g) Please provide the specific "system issues" that prompted the need fore each of the curtailments of each of the existing variable generation on the HELCO system for the last three years.

h) Please provide a list of the specific actions taken by HELCO to address the "system issues" in each instance in addition to curtailing the existing variable generation.

i) Please provide the frequency and duration of load shedding implemented by HELCO in the last three years that were specifically caused by the existing levels of variable renewable generation on the HELCO system.

j) Please provide data supporting that the occurrence of these load shedding.

k) Wouldn't deferral of NEM requests as proposed for the HELCO and MECO systems violate statute, specifically Chapter 269, Part VI, HRS? If not, please explain why not.

l) Is it the HECO Companies' belief that the Commission has the statutory authority to suspend the implementation of the statute on NEM?

m) Has HELCO quantified its fossil-fuel savings during the last three years due to the existing levels of renewable generation on its system? If yes, please provide the quantified savings. If no, please explain why not.

n) Has MECO quantified its fossil-fuel savings during the last three years due to the existing levels of renewable generation on its system? If yes, please provide the quantified savings. If no, please explain why not.

o) Please specify the projects that are included in the "planned" DGs indicated in Table 3, page 15. Please indicate which ones are NEM projects.

p) Please specify the projects that are include in the "planned/proposed" DGs included in Table 4, page 25. Please indicate which ones are NEM projects.

q) Plase explain how the queuing process will apply to the non-FIT projects – i.e., how non-FiT projects will be ranked or assigned a place in the queue list. For instance, will the PPA projects that are being negotiated be assigned at the top of the queue list?

HECO Companies Response:

a) The issues are numerous and not all can be addressed through studies soley by the HECO companies; in some cases research in the industry in general or investigations into ongoing technologies are necessary. An assessment is necessary to identify which of the issues necessitate study, prioritized relative to the overall system impacts and goals and with recognition for those issues that are causing reliability concerns on the system today. It is anticipated that this research and appropriate studies will be identified and conducted by the proposed Reliability Standards Working Group which has as a part of its overall responsibilities the identification of near-term, mid-term and long-term solutions to the issues presented and movement of those solutions them toward implementation as quickly as possible.

b) See response to subpart a.

c) The present state of system balancing and frequency control on the HELCO system is described in Attachment 3 of the HECO Companies Report on Reliability Standards filed February 8, 2010 ("Companies' Reliability Standards Report"), which describes the present frequency control issues on the system. Although not immediately quantifiable due to a lack of data, it is known that variable distributed generation will affect both system balancing and frequency control. The analysis showing the effect of additional levels of PV connected with typical IEEE 1547 trip settings on the frequency nadir for loss of a system generation (Hill 5) is shown in Figure 4 of Attachment 3 of the Companies' Reliability Standards Report. Additional issues on the power system which require investigation are described in Attachment 2 of the Companies' Reliability Standards Report.

d) Attachment 3 of the Companies' Reliability Standards Report describes the impacts on system balancing and frequency control, which is measured by the system frequency. The system frequency criteria is described in Table 8 of Exhibit 1 of the Companies' Reliability Standards Report. Due to the impacts of the existing levels of variable generation, HELCO is at times unable to maintain system frequency within the target normal range of operation. There are more numerous excursions into emergency control and the underfrequency load shed scheme required modification, in part due to the effect of wind ramps. The findings of the recently conducted study regarding aggregate loss of PV due to low-frequencies on the system (described in Attachment 3) confirms the observation that it is likely that loss of PV generation during loss of generation events is resulting in underfrequency load shed for some events which previously would not have resulted in load-shed. Studies are necessary to ensure that other reliability criteria are not violated with the addition of more distributed variable generation; for example, the ability to keep voltages within range, and for the system to remain stable through faults and contingencies. Such studies need to be evaluated in advance to avoid unintended negative impacts on the power system operation for all three Companies.

e) There is insufficient time to compile this information. Curtailments for excess energy occur routinely during off-peak hours. Curtailments also occur for reasons other than excess energy, depending on the impact of a particular resource on the system. The Companies anticipate that this type of information will be compiled as a part of the overall efforts of the proposed Reliability Standards Working Group.

f) The actual operational procedure to implement curtailment varies with each resource and the cause for curtailment. If the facility is dispatchable, then no notification is necessary. Other facilities have a control system interface for curtailment. For a discussion of the system operator guidelines for excess energy curtailments, please see the response to ZE-IR-107.

g) Curtailments for excess energy occur with some frequency during off-peak on any day with significant as-available production. The system issue requiring this curtailment, is excess energy, which if not managed would result in over-frequency. Curtailments have occurred for other system conditions including: line overloads, re-dispatch to permit line reclosing following planned or unplanned opening of certain cross-island lines, curtailment of particular facilities due to system impact such as frequency and voltage impact and behavior during faults.

h) For excess energy conditions, reduction in power production is the only means to balance the energy. Please see response to ZE-IR-107 for the protocol for excess energy curtailments. For the other instances where curtailment has been employed, the particular operational condition required curtailment of a particular resource as the most effective means to manage the particular operational condition (this applies to frequency deviations caused by rapid fluctuations in a particular wind plant or voltage impact from the plant, reduction of line overload in which the most effective generator reduction is taken regardless of the type of unit (including firm units), reduction in production as needed to reduce phase angle to allow reclose, and curtailment in response to a reliability concern created by failure to ride-through faults or other system event related to that facility). The lines subject to overload which at times required curtailment of a the wind plant in the North part of the Big Island (7200 and 7300) have been reconductored, so this particular curtailment has not been necessary.

i) The underfrequency events on the Big Island are listed in response to BP-HECO-IR-15 (a) along with their cause. The impact of variable PV cannot be quantified as it is not measured on the system; however modeling has confirmed that relatively small levels of PV with the standard IEEE 1547 frequency trip settings can result in load-shed for events which otherwise would have not reached load-shed levels. Most wind down-ramps to date have been mitigated by the operator bringing online fast-start diesels in time to avoid underfrequency load-shed however there is one instance in late 2009 where ramp-down of a wind plant caused underfrequency load shedding. This event occurred on 11/18/2009. Events where relative small generation losses (i.e.; between 10-15 MW) result in loss of underfrequency during daytime load conditions of around 160 MW or more, are likely to have had concurrent loss of PV during the underfrequency event as a contributing factor to the underfrequency load shed (though this cannot be proven at this time).

j) Please see response to BP-HECO-IR-15 (a) in particular for description of an event listed for 11//18/2009.

k) Hawaii Revised Statute Section 269-102 (Net Energy Metering) allows the Commission to amend the NEM rate structure or standard contract or tariff by rule or order[1]. Additionally, the Hawaiian Electric Companies have since clarified that they intend to continue accepting NEM applications up to existing program levels.

l) It is the understanding of the HECO Companies that the Commission has the statutory authority to modify the NEM program consistent with statute.

m) Tracking the cost impacts of variable generation on fossil fuel is difficult to quantify as it requires a production simulation which captures the variability of the renewable energy on, at a minimum, an hourly basis; curtailment issues, and reserve requirements. Planning tools today have difficulty in capturing such detailed information. A total analysis of cost impact would also need to include the impact on system losses, reserve requirements, and the costs of the increased number and magnitude of automatic generation control actions on the conventional units under AGC dispatch. Finally the analysis would need to include the costs paid to the renewable energy providers. Studies to make an assessment of these costs are one of the items identified in the conclusion section of Attachment 3.

n) MECO has not quantified its fossil-fuel savings during the last three years due to the renewable generation on its system. MECO has experienced reduced run-time hours on selected fossil-fuel generators because of as-available renewable generation. The fossil-fuel savings from the reduced run-time hours on certain generators is offset to some degree by having to run other fossil-fuel generators less efficiently to accommodate the acceptance of as-available power and to maintain regulating reserves. While calculating fossil-fuel savings based on reduced run-time hours may be possible, the fossil-fuel usage due to inefficiencies brought on by the acceptance of as-available renewable generation is not captured in MECO's Energy Management System. Additionally, most distributed renewable generation acts to lower the load, but the exact amount of load reduction (in MWhrs) and the associated fuel savings is not known.

o) The planned projects were those projects in late December 2009, for which interconnection process was begun. The majority of planned PV are NEM projects.

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[1] See Decision and Order No. 24089 in Docket No. 2006-0084, filed March 13, 2008 approving the increase of : 1) the maximum size of eligible customer generator that qualifies for NEM, from 50 kW to 100 kW; and 2) the system

p) Projects categorized as "planned" are projects that encompass pre-approved NEM and standard interconnection agreement ("SIA") projects. The NEM total is 411.8 kW and the SIA total is 131 kW. Projects categorized as "proposed" are projects for which a non-utility generation (NUG) application has been submitted to the Company. The specific project information is confidential until the actual Power Purchase Agreement negotiations are completed and therefore cannot be provided at this time.

q) The queuing procedures proposed for FIT will only apply to FIT projects. An overall prioritization process among the various contracting mechanisms continues to be discussed both internally at HECO and with the Independent Observer.

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cap from 0.5% to 1.0% of system peak demand.

DBEDT/HECO-IR-6

Ref.: Attachment 2

a) Please provide the names, titles, and agencies represented by the "task force created to identify areas of concern and study" for the HELCO system mentioned on page 3 of the referenced attachment.

b) Please identify the "task force" recommendations provided in the referenced attachment that HELCO has implemented.

HECO Companies Response:

a) The Task Force was an internal group within HELCO consisting of Jay Ignacio (HELCO President), Jose Dizon (HELCO General Manager), Michael Bradley (Assistant Operations Superintendent), Curt Beck (Energy Services Manager), Norman Verbanic (Production Manager), Jon Arizumi (Energy Services), Tom Cummins (Engineering Manager), and Tony Sianez (T&D Engineer).

b) The task force made a number of recommendations for study on the distribution system and transmission system anticipating increasing DG penetration. As noted on page 7 of Attachment 2 of the HECO Companies Report on Reliability Standards filed February 8, 2010, the focus of near-term efforts was on the issue of nuisance trips as the most immediate concern. Studies focused on nuisance trips and aggravated underfrequency events due to aggregated loss of DG led to changes to the underfrequency load-shed scheme which were implemented in 2009. As a result of the study findings, HELCO initiated steps to change the frequency trip setting for existing and anticipated DG projects, where possible from 59.3 Hz to 57 Hz with minimum delay of 300 seconds to minimize aggregated loss of DG during events. However, this measure has not been proven in the field and the actual behavior will need to be further evaluated and monitored during disturbances. HELCO has also implemented some of the recommended changes for the distribution system such as Direct Transfer Trip (DTT) on distribution feeders to trip a large DG facility when the substation breaker is open to prevent islanding of the DG resource, voltage regulation requirements of the DG resource, monitoring of the large DG resource (in development for a concentrated solar project), and change of reclose policy. HELCO has also developed an under voltage ride-through requirement to define the voltage conditions under which facilities may trip but review needs to ensure these settings are applicable to DG resources. The ranges have not been implemented and also require further field monitoring and testing in the field. To address the absence of system impact data due to capacity factors of DG, availability, correlation between sites and regional characteristics of the resource, HELCO has implemented a pilot solar monitoring project to estimate PV production base on a series of real-time PV sensors installed throughout the system substations equipped with SCADA/EMS interfaces. Presently the 45-sensor system provides operators a visual on potential PV variations throughout the system. Once correlated with the known capacity of nearby DG, the tool will provide an approximation of available PV generation on the HELCO system. As mentioned, these proactive measures are some of the firsts of their kind to be implemented and the HELCO grid is leading the Hawaiian islands and the nation in adopting measures and strategies to reliably and economically transform the grid to maximize transmission and distribution level variable resources.

Response to

Hawaii Renewable Energy Alliance's

Information Requests

HREA-IR-1
Ref.: Page 7.

Regarding Interconnection Requirements Studies ("IRS) reference in the table at the bottom of the page, since HREA is now aware that IRSs are being required for residential PV projects on the Big Island, is it HECO's intent that all projects will require IRS? If not, what are the criteria for determining whether an IRS will be required? Also, will there be a fixed rate for Tier 1, Tier 2 and Tier 3 IRSs? If not, why not?

HECO Companies Response:

As stated in the HECO Companies' Rule 14H, additional technical study may be required when the aggregate generating capacity per distribution feeder exceeds 10% of the peak annual KVA load of the feeder. A fixed rate for all interconnection studies is not possible as the costs are highly dependant on the specific project.

HREA-IR-2

Ref.: Page 9.

Regarding the application process, will all applications received be posted on HECO's web-site, including key information such as technology type, size, location and a circuit identification number? If not, why not?

HECO Companies Response:

Only the projects in the queue will be posted on the FIT website. During the January 2010 workshop, the Independent Observer sought feedback from the parties regarding balancing transparency of the projects in the queue with privacy concerns for the applicants, in particular, the individual homeowner type applicant. The information posted on projects in the queue will be developed in consultation with the Independent Observer. The parties will be allowed an opportunity to provide feedback on the proposed queue information posting before it is finalized.

<u>HREA-IR-3</u>
Ref.: HECO presentation at the Second Technical workshop (slide 6, Location Value Maps)

Is it now HECO's intent to use the Location Value Maps to indicate "high potential areas" for FIT development? If so, how would this be accomplished? For example, would the maps be published ahead of the roll-out of the FIT on each island?

<u>HECO Companies Response:</u>

As stated on HECO's website, the Locational Value Maps ("LVM") are envisioned to be an informational visualization tool that will identify geographic areas of distribution system growth within the next 3-5 years where distributed resources and energy efficiency could be beneficial within the existing transmission and distribution system limits. The LVM is also envisioned to identify at a point in time, the level of distributed generation on distribution circuits as a percentage of peak circuit load in a general geographic area. HECO is reviewing how frequently the LVMs will be updated.

HREA-IR-4

Ref.: HECO presentation at the Second Technical workshop (slide 7, Exhibit 3)

Have there been any changes to this flow chart? Specifically, in reality isn't the "IRS Required Diamond" really part of the "Queue Block?" And shouldn't there be a "breakout" of the Queue Block which indicates all of the steps required for projects to exit to the "Standard Offer Contract" block?

HECO Companies Response:

No changes have been made to the referenced flow chart. An applicant whose project triggers an interconnection study may elect not to proceed with the study and will have his reservation deposit immediately refunded. Adding additional clarification to the diagrams can be done in conjunction with future workshops.

HREA-IR-5.

pgs. 1 and 2 of the report, not withstanding what may happen on the mainland, please define "system reliability?" For example for each grid, is system reliability the:

1. probability of maintaining a grid frequency of 60 hz ± 0.3 hz? If so, under normal operating conditions what is the probability? For example, if it is 95% what is the level of confidence that this probability is achieved? Moreover, given that there isa cost to maintain said system reliability what are the criteria for setting the grid frequency criteria, i.e., the 60 hz ± 0.3 hz or whatever it is. In HREA's opinion HECO has not be "upfront" with the Parties as to the what and why the frequency goal. Instead, all we hear is how hard it is to maintain system frequency.
2. probability of maintaining system voltage of 120 volts ± 10 volts at residents, 240 or 480 volts ± X volts at commercial or industrial customers sites? HREA believes this is an important consideration, but there has been little discussion on this by HECO.
3. probability of maintaining the load (loss of load probability? Please explain what criteria are used by HECO for "loss of load" and what the real goals are. Moreover, what measures are needed by HECD to minimize the "loss of load" probability and at what costs.
4. X or other factors in addition to the above? If so, please explain.

HECO Companies Response:

System reliability is the degree to which the elements of the electrical power system operate in coordination resulting in electricity being delivered to the customers within accepted standards, in desired amounts and with appropriate characteristics (quality of power). The degree of reliability may be measured by the frequency, voltage, duration and magnitude of adverse effects on the electric supply including loss of load. The Hawaiian Electric Companies measure system reliability following common industry measures (e.g., SAIFI, SAIDI and CAIDI as defined in IEEE Standards). These measures or indices consider aspects such as connected load, duration of interruption (seconds, minutes, hours, days), number of customers interrupted and the frequency of occurrence of interruptions.

1. The HELCO and MECO systems are currently experiencing frequency excursions due to resource variability. They have instituted curtailment practices to bring system frequency

within operating range to protect other interconnected machinery and customer loads. HELCO efforts and issues have been presented at a number of technical venues and further documented in Attachment 3 of the Reliability Standard filing. Page 3 provides detailed descriptions for the range of frequency targets and action levels. The desired target is to maintain frequency without shedding customer load where cost implications can be significant due to unavailability of service. See page 3 of Attachment 3 for details on resources and controls for maintaining frequency. Average frequency error on the HELCO system has increased with the addition of the variable renewable facilities.

2. The Hawaiian Electric Companies agree with HREA's assessment that maintaining system voltage is a fundamental part of system reliability on the transmission system down to the customer levels. Maintaining power quality begins at the system levels and the Hawaiian Electric Companies work to maintain system voltages within IEEE1547 and ANSI C84.1 limits at all times for flicker and voltage regulation. As noted on pages 36 and 37 of the Company's FIT Reliability Standards, Table 8 highlights some of the major operating criteria which need to be reassessed as distributed generation (DG) penetration levels increase. A system is less reliable if it suffers from numerous system outages and interruptions caused by inconsistent quality of power. Power quality may also be defined as "the measure, analysis, and improvement of bus voltage to maintain that voltage to be a sinusoid at rated voltage and frequency." Transients including flicker, voltage sags, impulses, harmonics, and phase imbalance are power quality concerns that impact system reliability. Power quality problems are often momentary, and thus difficult to diagnose and will require continuous monitoring equipment on the

system. Power quality problems can have major economic impact especially on sensitive manufacturing and medical loads. As a result maintaining voltage levels and power quality is a major factor contributing to system reliability.

Source of power quality come either through the utility distribution system or are introduced by the customers themselves based on devices being interconnected to the system. The voltage measures described on Table 8 cover utility measures and Rule 14H Interconnection equipment requirements (e.g., on ride-through) help to standardize customer interconnected devices. Additional dialog and collaboration amongst developers, manufacturers and utilities will need to occur to improve power quality impacts on system reliability.

3. Loss of load probability (LOLP) looks at providing adequate levels of generating resources to meet load at or within an acceptable level. Traditional LOLP does not model the reliability of the transmission or distribution system where an outage may occur. LOLP calculations have been used to provide guidance for prudently planning system reserves to handle contingencies (e.g., single worst or two or three) at the time of heaviest load. For each of the Hawaiian Electric Companies, the planning criterion is a function of the mix of generating resources and their response capabilities, system characteristics such as generator reliability, load volatility, correlation of summer peak loads, and unit de-rates. Summarized in Table 8 on Page 37, are the Companies' existing approaches for maintaining load based on experience operating the grid. For HECO, system requirements are to maintain enough spinning reserves to meet loss of the largest operating unit on line and will not be further reduced by amount of interruptible loads

available. As noted on the "Need to Reassess as Renewable Penetration Levels Increase" column on Table 8, all the systems will require additional system level studies to determine new LOLP based on the characteristics of the renewable resources and required must-run units. Costs associated will need to be assessed in the studies.

4. Other factors related to system reserves, ramp ratés responsiveness, minimum must-run units for system stability and managing bi-directional flow from distribution to transmission systems all need to be further assessed in light of increasing levels of variable resource penetrations. Additionally, new utility infrastructure to monitor, communicate and control respective systems along with new operating procedures will be needed to maintain system reliability for the benefit of all connected load on the system.

HREA-IR-6.

pg. 2, regarding DBEDT's recommendations for the need for third-party studies of grid operations in HECO's service territory, in fact, have not such studies already been conducted within the past several years? Please identify the specific studies, who conducted them and when, and provide copies of all reports delivered to HECO.

HECO Companies Response:

The Companies conduct system investigation studies on a continuous basis to track and address changes occurring on the system. They can be internal system studies focused on improving specifics of our generators, control systems or planning for future needs. They can also be IRS studies performed for specific projects (PPAs, NEM, SIA) at a customer location applying to interconnect to the grid. As high penetration impacts on the distributed system are already being observed on the HELCO grid, specific studies by third-party consultants have been performed for customer locations as early as 2002. Studies evaluate the lines impacted, type of resources and existing loads on the feeders and help identify issues. As many of these technical studies were conducted for specific customers, internal use only and contain system sensitive detailed information or identify vulnerabilities on the system, copies are not publicly available. Depending on the severity of the impacts, studies will either provide specific recommendations on how best to accommodate the project with additional grid upgrades including protection devices and other measures or provide justification for not interconnecting due to costs or other grid considerations (e.g., other customer loads that may be impacted).

For purposes of investigating the impact of variable distributed generation on the integrated systems on the islands, other than the specific project interconnection studies focused on the distribution system, no other prior comprehensive system level study (integrating distribution level impacts up to the transmission system) has been completed to determine how much variable, non-dispatchable renewable DG resources can be accepted on the current systems. As part of the current FIT process, HECO commissioned a third-party consultant to begin baseline studies needed to support the FIT evaluation of the full system (transmission and distribution impacts). BEW Engineering was commissioned in late October to help baseline existing conditions on the Company grids down to the distribution levels. BEW's prior work in California to develop a transparent and collaborative process with stakeholders to begin investigating the locational value of renewables on the grid provided solid foundation for tailoring studies for the island grids. As presented during the November Workshop and explained on page 30 of the Company's FIT Reliability Standards filing, "with increasing variable renewable generation resources connected at both the transmission and the distribution levels, a more integrated process of evaluating distribution level impacts on system performance is critical, especially when potential bi-directional flow of electricity may be encountered." The proposed Methodology considers the integration of both the transmission and distribution level impacts and calls for opportunities to engage with stakeholders to develop inputs for consideration.

Preliminary baseline assessments by BEW Engineering were provided as Attachments 1, 5 and 6 to the Companies' FIT Reliability Standards. BEW Engineering recommends more detailed assessment studies but within the time period dictated under the FIT proceedings, the preliminary observation reports were provided. The Companies' own evaluations on curtailment impacts, feeder circuit impacts and control capabilities were also completed and provided as Attachments 2, 3, and 4.

The Companies recommend additional follow-on studies within the context of a Reliability Standards Working Group and following the proposed methodology to evaluate the integrated system. The Companies plan on continuing to work with BEW Engineering, other third-party consultants, and technical experts to develop the necessary data for capturing the DG characteristics, model latest inverter technologies and conduct system impact studies, transients stability studies and other modeling studies to best accommodate the influx of renewable technologies on the island grids within the context of the Reliability Standards.

HREA-IR-7.
Regarding the BEW Engineering Report which is summarized in Attachment, please provide a copy of the complete report.

HECO Companies Response:

Attachments 1, 5 and 6 are the completed baseline reports at the time of filing for Oahu, Lanai and Molokai. To perform the baseline studies, considerable data must be pulled together and the model developed to simulate each island grid. BEW Engineering staff prepared data, developed the models for both the transmission and distribution systems of Oahu and worked closely with HECO planning staff to validate initial modeling runs. As such, additional detailed analysis and distribution level studies can now be performed. Third-party study efforts need to continue and will be integrated into the utility-stakeholder process to further investigate grid issues in a collaborative fashion.

<u>HREA- IR-8</u>
Regarding HECO's intent moving forward on Maui and the Big Island, please clarify the following regarding section E, starting on page 12 of Exhibit 1:

1. Will there be more opportunity to integrate new renewable DG at the sub-transmission or transmission level compared to distribution, or vice versa? Please explain.

2. Will HECO consider operating the grids "full-time" the way it is doing during the night-time (low load) periods, i.e., with only a minimum "must-run" generation? Specifically, given that PV can provide a good load match during the daytime hours, why can't more PV be allowed and back-up by the combined cycle plant at Keahole running on diesel?

3. Will HECO now advance its planning for pumped-hydro and battery storage? Please explain.

4. Is HECO willing to form one or more utility-stakeholder groups to investigate the grid operational issues in a collaborative manner?

<u>HECO Companies Response:</u>

1. Both HELCO and MECO are continuing to move forward with negotiating power purchase agreements for planning projects at the transmission level, including:

    - Two proposed wind farms on Maui (KWP II & Sempra Auwahi) with battery storage systems (42 MW);
    - Two proposed biomass plants on the Big Island (Tradewinds & Hu Honua - 28 MW)
    - Expansion of the PGV geothermal plant on the Big Island (8 MW)

    Additionally, even though the addition of significant new resources should be the subject of additional studies and consideration by a proposed Reliability Standards Working Group, HECO, HELCO and MECO are currently *continuing to accept and connect he Net Energy Metering (NEM) projects and projects seeking Standard Interconnection Agreements.* In some cases there may be individual circuits that are already so heavily loaded with intermittent renewable energy that adding more could create reliability problems for customers on that circuit. The Companies will work with the developers/customers in those cases to help them find other options.

The Companies' goal remains integrating as much of all kinds of cost effective renewable resources on their grids as possible, consistent with the Companies' overarching clean energy goal to stabilize and, if possible, reduce the cost of electricity now produced mostly by fossil fuels. In doing so, the Companies must:

- Meet their obligation to provide and ensure reliable service for all customers;
- Ensure that output from existing renewable energy projects is not curtailed as new projects are added; and
- Avoid situations where new projects are added such that the owners cannot get full value from their projects because the grid cannot reliably accept the electricity.

These are not simple issues and the Companies take their responsibility to meet all of these goals very seriously.

2. For the HELCO system, during periods of high variable output the system indeed will be operating similar to the manner it does now off-peak. This is illustrated through the stack-charts in figures 5 and 6. Under such conditions, the supply of renewable energy for existing and planned resources exceeds the demand on the system (in the absence of demand growth). There are potential reliability implications of operating at minimum load, these are discussed in Attachment 4, beginning at page 5. Given the renewable energy projects in place, and in the near future; the addition of solar resources will often be displacing other renewable energy providers rather than displacing fossil generation. The Hawaiian Electric Companies are exploring various avenues to facilitate the uptake of renewable resources including backing down conventional fossil generation to a minimum "must-run" level. Backing down of units must be carefully planned and studied so as to maintain adequate and responsive generation to 1) economically

"backup" variable renewables, 2) maintain dispatchability of supply to meet demand at all times and 3) plan to handle imbalances and contingency events. Table 8 of the HECO Companies Reliability Standards Report filed February 8, 2010, provides a summary of the actions and studies that the Companies are investigating or recommend needs to be investigated in order to determine how best to accommodate additional renewable resources that do not adversely compete against each other. Analysis provided in Attachment 4 of the Companies' FIT Reliability Standards already assumes minimum "must-run" levels on the respective systems. With increasing variable renewable resource levels, more "backup" may be needed from firm generation or other dispatchable technologies.

From a supply standpoint, BEW Engineering provided an initial capacity planning (steady-state) evaluation of a high PV DG penetration output with light load conditions for the Oahu grid (Attachment1 to the FIT Reliability Standards Report). Under this light load day (typical Sunday load), the forecasted day peak is just under 800 MW and evening peak is slightly above 820MW and system minimum load is around 500 MW with minimum utility units online and at minimums to provide for system stability and spinning reserves. Shown in Figure 3 from Attachment 1 is the effect of load reduction or daytime peak shaving due to DG PV during the hours of 9am to 4pm for this light load condition. Analysis looked at identifying potential areas of system impact with increasing penetration levels of DG ranging from 5% to 15% of peak load (1200 MW for Oahu) at 5% increments. Additional load reduction is seen and the day time peak can potentially be reduced with 5% (60 MW) up to 15% (180 MW) DG PV. HECO units along with other must-run generation are held at just above minimum load of 500 MW accordingly as the DG increases. As the DG PV resource begins to taper off around 4 to 6 pm depending on the time of year, the analysis shows that unless additional units were committed, there would be a shortfall of generation to meet the evening load rise as the DG PV would be offline and have no contribution on reducing the evening peak condition.

The Companies currently operate the grid and generation portfolio to service load. This requires scheduling and dispatching existing units and PPAs in an economically efficient mode under normal operating conditions. Variable renewable generation (primarily wind and PV) by virtue of their variable solar and wind sources, are unscheduled or uncontrolled generation to the system. Wind and solar output changes can occur rather quickly over seconds to minutes and last minutes to hours. These changes impact the utilities ability to balance system generation and demand and maintain system frequency. As explained in Attachment 3 of the Companies' FIT Reliability Standards filing, resources are set aside to contribute to balancing and maintaining frequency control either as spinning or non-spinning reserves. The reserve levels are maintained to cover critical system contingencies but as more renewable resources are added, these critical system contingencies may not be sufficient to respond to changes in wind and solar and also supply sufficient resources to cover the loss of a generator. Complicating matters is that depending on the conditions (e.g., storms, seasonal weather, emission control days, maintenance outage), only select units may be available to provide backup and plan for load spikes or other contingencies.

As more demand side generators come online at the customer side under programs like FIT, additional system studies must be pursued so as to best plan options and integrate with the existing resources on the grid (including existing must-run units and PPAs). The HECO Companies have proposed a Reliability Standards Working Group to oversee these studies and to develop strategies and options to address the increasing penetration of renewables.

3. The Hawaiian Electric Companies will indeed accelerate their evaluation of the performance capabilities, operational requirements, and costs of energy storage technologies (e.g., pumped storage hydroelectric, compressed air energy storage, batteries, flywheels) to assess their ability to help grid operations, including the integration of more renewable energy resources on island grid systems. This evaluation will be conducted in parallel to the proposed Reliability Standards Working Group efforts described in the HECO Companies' February 26, 2010 Response to Commission Letter of February 19, 2010. The Companies assess energy storage technologies, applications, and projects through technical evaluations, project feasibility studies, and research, development and demonstration (RD&D) projects.

The Companies have also been active in pursuing federal ARRA stimulus funds to support pilot demonstration of multi-chemistry storage technologies to help variable renewable technologies meet system performance requirements by providing regulating capability as well as ability to manage excess energy issues. In 2009, the Companies teamed with industry and Sandia National Laboratory (Sandia), the leading national laboratory on storage technologies, and led a proposal effort to secure $10M for demonstration of a multi-chemistry storage technology for the islands. Though our proposal was not selected, the teaming relationship with industry and Sandia raised a number of critical gaps including better operational awareness of different storage technologies and appropriate controls we will likely require for the islands grids to complement our existing generation portfolios. Data issues and the lack of operational information to appropriately tune the controls of the storage technology were identified as critical priorities. As such, the Companies are pursuing several efforts to gain practical operational information to better support deployment of storage technologies in partnership with industries, HNEI, ORNL and U.S. DOE. Efforts currently underway include:

a. Upcoming demonstration scale pilot storage efforts for Hawaii

- MECO is working with wind developers to integrate storage technologies to help mitigate the variability of wind. (http://www.mauinews.com/page/content.detail/id/526614.html)

- The Companies are also working with HNEI to pilot a demonstration-scale system on the Big Island to gain some practical experience using storage. On Maui, efforts are underway to integrate storage technologies as part of a smart grid demonstration. (For more information on HNEI and efforts, http://www.hnei.hawaii.edu/history.asp)

b. Gaining operations data for designing appropriate control strategies for storage

- Federal funding has been secured via ARRA stimulus funds for HELCO to deploy high quality phasor monitors (PMUs) at critical locations on the Big Island to monitor and manage the variable renewables currently on the islands. Information will be used to better inform system operations and provide additional system information currently not available to the operators.

- Federal partnership with the Pacific Northwest National Laboratory (PNNL) for MECO to begin deploying PMU monitoring at critical locations on the grid and capture high resolution system data on voltage, phase-angle, frequency, VAR and other parameters necessary for programming the controls for battery technology and target future opportunities for deployment of such technologies. The system information captured will also enable appropriate modeling for future scenario-based planning.

As storage technologies are not all equal, their performance must be tuned with appropriate system data in order to respond to system needs. Storage technologies on both the customer and utility side will provide different benefits, and the Companies are actively pursuing funding and industry partnerships to improve the knowledge base and operational understanding to be able to integrate mitigation options such as appropriate storage technologies into the systems. Development and deployment of energy storage projects, whether utility-owned or third-party owned, will help guide and shape the Companies' resource plans and requirements to maintain and/or improve grid operability and reliability utilizing a wide variety of promising technologies.

4. Yes. Please see the HECO Companies Response to Commission Letter of February 19, 2010, filed February 26, 2010 in this proceeding.

Response to

The Solar Alliance and Hawaii Solar Energy Association's

Information Requests

SA/HSEA-QI-IR-1

Ref.: Merrimack Energy Group, Inc. Report ("Merrimack Report") at 10; FIT Release Schedule.

a. Please explain in detail the rationale for "A Release of an initial increment of Tier 1 queue capacity up to the 5% reservation, less converted NEM projects." Please provide all supporting documents.

b. Please explain in detail how "A Release of an initial increment of Tier 1 queue capacity up to the 5% reservation, less converted NEM projects" is consistent with the Commission Decision and Order filed in this docket on September 25, 2009.

c. Please explain in detail how "A Release of an initial increment of Tier 1 queue capacity up to the 5% reservation, less converted NEM projects" will not hinder the implementation of an effective FIT program in Hawaii.

d. Approximately how much energy is "an initial increment of Tier 1 queue capacity up to the 5% reservation, less converted NEM projects."

HECO Companies Response:

a. Please refer to Section V. of the Merrimack Report.

b. "The commission...will reserve five percent of the FIT cap of each of the HECO Companies for projects under 20 kW" (reference D&O page 57). Also, please refer to "Current NEM customers or owners of new projects that are eligible for both NEM and the FIT will receive a one-time choice to opt for either NEM or the FIT." (D&O page 21).

c. As indicated in Section V of the Merrimack Report, the Independent Observer's recommendation of an initial incremental release will allow for continual evaluation and opportunity for improvement at each stage. HECO believes adoption of the Independent Observer's recommendation will foster, not hinder, the successful implementation of the program. . Subsequent releases that take advantage of lessons learned from the initial releases of additional tier capacity will provide for continual process improvement that will benefit both the potential project applicants/developers as well as the HECO Companies.

d. For HECO, this initial increment of Tier 1 capacity of 5% is estimated to be approximately 3 MW. Assuming a majority of project applications at the maximum Tier 1 size of 20 kW, this could translate to an initial queue of more than 150 projects if the initial queue is fully subscribed.

SA/HSEA-QI-IR-2

Ref.: Merrimack Energy Group, Inc. Report ("Merrimack Report") at 10; FIT Release Schedule; "Initial Tier 2 Release. A release of an initial amount of Tier 2 queue capacity."

a. What amount is the HECO Companies anticipating for the "initial amount"? Please explain in detail how the HECO Companies came up or plan to come up with this "initial amount."

b. The Merrimack Report states that the IO will be consulted as to the "timing and amount" of the "initial amount"; will the parties to this Docket also be consulted? Please detail the steps and timeline for this process, with reference to specific dates if possible.

c. Will the "timing and amount" of this "initial amount" be subject to Commission approval prior to implementation?

d. Please explain in detail the rationale for "A release of an initial increment of Tier 2 queue capacity." Please provide all supporting documents.

e. Please explain in detail how "A release of an initial increment of Tier 2 queue capacity" is consistent with the Commission Decision and Order filed in this docket on September 25, 2009.

f. Please explain in detail how "A release of an initial amount of Tier 2 queue capacity." will not hinder the implementation of an effective FIT program in Hawaii.

HECO Companies Response:

a. The amount of queue capacity for the initial Tier 2 release has not been determined at this time. As stated in the Merrimack Report (page 10), the amount will be agreed to after consultation with the IO.

b. The Commission and parties will be consulted as to the timing and incremental queue capacity on each proposed release.

c. Yes, HECO proposes to seek Commission approval prior to implementation.

d. See HECO's response to SA/HSEA –QI-IR-1, part c).

e. At page 93 of the Commission's Decision and Order, the Commission directed that the Independent Observer oversee the queuing process for FIT projects, assist in developing the queuing process, and monitor how the utility administers the queue. The Independnet Observer has recommended an initial phased release to enhance the overall effectiveness of the FIT program. The Hawaiian Electric Companies concur with the Independent Observer's recommendation.

f. See HECO's response to SA/HSEA –QI-IR-1, part c).

SA/HSEA-QI-IR-3

Ref.: Merrimack Energy Group, Inc. Report ("Merrimack Report") at 11; FIT Release Schedule; "Initial Tier 2 Release. A release of an initial amount of Tier 3 queue capacity."

a. What amount is the HECO Companies anticipating for the "initial amount"? Please explain in detail how the HECO Companies came up or plan to come up with this "initial amount."

b. The Merrimack Report states that the IO will be consulted as to the "timing and amount" of the "initial amount," will the parties to this Docket also be consulted? Please detail the steps and timeline for this process, with reference to specific dates if possible.

c. Will the "timing and amount" of this "initial amount" be subject to Commission approval prior to implementation?

d. Please explain in detail the rationale for "A release of an initial increment of Tier 3 queue capacity." Please provide all supporting documents.

e. Please explain in detail how "A release of an initial increment of Tier 3 queue capacity" is consistent with the Commission Decision and Order filed in this Docket on September 25, 2009.

f. Please explain in detail how "A release of an initial amount of Tier 3 queue capacity." will not hinder the implementation of an effective FIT program in Hawaii.

HECO Companies Response:

Please note that the subparts to the above IR were re-labeled from subparts e, f, g, h, g, h, to a,b,c,d,e,f.

a. See HECO's response to SA/HSEA-QI-IR-2a.

b. See HECO's response to SA/HSEA-QI-IR-2b.

c. See HECO's response to SA/HSEA-QI-IR-2c.

d. See HECO's response to SA/HSEA-QI-IR-2d.

e. See HECO's response to SA/HSEA-QI-IR-2e.

f. See HECO's response to SA/HSEA-QI-IR-2f.

<u>SA/HSEA-QI-IR-4</u>

a. How is the HECO Companies proposal to do an initial increment amount for Tiers 1, 2 and 3 consistent with its proposal in the PV Host Docket to install 4 MW on the HECO system for each of the two years and 2MW on both the HELCO and MECO system for each of the two years? Please explain in detail.

b. Rather than doing an initial increment amount for Tiers 1, 2 and 3, wouldn't it be more prudent for the HECO Companies to suspend or withdraw its PV Host Application to allow for "continual evaluation and opportunity for improvement at each stage" of the FIT program? If not, please in detail why not.

<u>HECO Companies Response:</u>

a. The FIT Queuing and Interconnection Procedures and Proposal for Initial Implementation filed by the Hawaiian Electric Companies on February 1, 2010 apply specifically to the FIT program, and therefore, would not govern the development and deployment of PV Host projects.

b. As stated on page 4 of the HECO Companies' Response to Commission Letter of February 18, 2010, filed February 26, 2010 in this proceeding "...in light of the FIT Reliability Standards filing, the Hawaiian Electric Companies will propose in the PV Host proceeding that the PV Host program for Maui and the Big Island be deferred indefinitely, at least until the intermittent renewable integration issues are resolved. HECO still desires to implement the PV Host program on Oahu, and will continue with the application review process."

SA/HSEA-QI-IR-5

Ref.: Merrimack Energy Group, Inc. Report ("Merrimack Report") at 11; "Release of Subsequent Queue Capacities. The Company would determine which Tier or Tiers would then be designated for additional releases after consultation with the IO and consideration of system reliability, curtailment, and potential pent up demand in any Tier category. This could result in issuing a release of additional queue capacity in any single or all of the three of the Tiers."

a. Will the parties to this Docket have any say as to when subsequent queue capacities are released? If not, why not.

b. Please explain in detail what factors you will be applying in regards to "system reliability" in making the decision as to when subsequent queue capacities are released.

c. Please explain in detail what factors you will be applying in regards to "curtailment" in making the decision as to when subsequent queue capacities are released.

d. Please explain in detail what factors you will be applying in regards to "potential pent up demand in any Tier category" in making the decision as to when subsequent queue capacities are released.

HECO Companies Response:

a. HECO intends to consult with the parties prior to the release of subsequent queue capacities.

b. The information developed from the system reliability studies will be factored into recommendations presented to the parties and the Independent Observer regarding proposals for the amount of subsequent Tier capacities.

c. HECO's proposals for subsequent tier capacities will also be consistent with the Commissions D&O that advises the utility need not interconnect projects that would likely face significant curtailment or cause significant curtailment for existing renewable energy generators.

d. The factor that will be considered in regards to "potential pent up demand in any Tier category" will be the amount of applications that were denied due to queue capacity being filled as well as feedback from the parties and the public.

SA/HSEA-QI-IR-6
Ref.: Merrimack Energy Group, Inc. Report ("Merrimack Report") at 10; "In consultation with the IO, Hawaiian Electric will reserve the right to impose additional rules or procedures as necessary to ensure that the FIT program is proceeding in accordance with the Commission's Orders."

a. Please provide specific examples of the additional rules or procedures you are contemplating may need to be imposed.

b. Before these additional rules or procedures are imposed, will the parties to this docket be provided with an opportunity to review and comment? If yes, please detail the steps and timeline for this process, with reference to specific dates if possible.

c. Will these additional rules or procedures be subject to Commission approval prior to being imposed by Hawaiian Electric?

HECO Companies Response:

a. Due to the expected higher levels of project development risks for the Tier 3 sized projects, it may be appropriate to request additional information from project applicants that are not necessary for smaller Tier 1 and 2 projects (i.e. environmental permits, land use approvals, etc.). This information may be used to conduct assessments to prioritize projects for the queue.

b. Yes, the parties will be provided an opportunity to provide feedback at future workshops or may share comments directly with the Independent Observer at any time.

c. To the extent appropriate, HECO anticipates that once identified, the additional rules or procedures will be submitted to the Commission for approval.

SA/HSEA-QI-IR-7
Has the IO met privately with any of the other parties to this Docket, besides the HECO Companies?

HECO Companies Response:

HECO is aware that the IO has met with the Commission, but has no knowledge as to whether the IO has met privately with any of the other parties to this Docket. The IO is not obligated to report to the Company on any meetings or consultations with any of the parties or the Commission.

SA/HSEA-QI-IR-8

Ref.: Merrimack Energy Group, Inc. Report ("Merrimack Report") at 11; "Reliability Team."

a. Please identify who will be on the "Reliability Team."

b. Will any intervenors in the FIT Docket be on the "Reliability Team"? If yes, please identify those parties and explain how they were selected. If not, why not?

HECO Companies Response:

a. SA/HSEA may be referring to the Reliability Standards Working Group that is being proposed by the HECO Companies. Please see the Companies' response to Commission Letter of February 19, 2010, filed February 26, 2010 in this proceeding.

b. Please see the response to subpart a. above.

SA/HSEA-QI-IR-9

Ref.: Merrimack Energy Group, Inc. Report ("Merrimack Report") at 8; Interconnection Assessment and Review Process; "FIT projects will be treated on an equal basis compared to other distributed generation in terms of interconnection and integration with the grid. The ability of each of the Companies' grid systems to integrate distributed generation projects will be subject to the Reliability Standards that are being developed in this docket as well as subsequent policy decisions".

a. How do the HECO Companies define distributed generation? Please provide a reference for the definition. Would the HECO Companies definition include projects in its proposed PV Host Program?

b. If yes, wouldn't this result projects in its proposed PV Host Program competing with FIT projects for interconnection and integration on the grid? If not, why not?

c. Please define with specificity what "subsequent policy decisions" to which the Merrimack Report is referring.

HECO Companies Response:

a. As stated in Hawaiian Electric Companies' Preliminary Statement of Position, Exhibit A of Docket No. 03-0371 (Instituting a Proceeding to Investigate Distributed Generation in Hawaii) filed on May 7, 2004, "As defined by the Commission in this Docket, distributed generation involves the use of small scale electric generating technologies installed at, or in close proximity to, the end-user's location. The Companies have not attempted to define "small" for purposes of this proceeding, but note that "small" should be construed relative to the utility's system loads, and to the loads of large customers."

The definition cited above adequately describes proposed PV Host projects as well.

b. Distributed generation projects, including those developed under the FIT and PV Host Pilot programs, will be treated on an equal basis in terms of interconnection and integration with the grid. Accessibility to the grid by these projects may be subject to the specific distribution circuit at which the project is located and the level of penetration of distribution generation on that particular circuit.

c. In situations where there is limited space on the grid to accommodate proposed distributed generation projects through the various development mechanisms, it is anticipated that policy decisions by the Companies will need to be made with regards to prioritizing which projects are interconnected. As an example, the HECO Companies will propose to defer the PV Host program on Maui and the Big Island indefinitely, due to the issues raised in the Reliability Standards filing for those islands.

SA/HSEA-QI-IR-10

a. Please specify how much time an average IRS will take, and how much it will cost.

b. While an IRS is being conducted for a FIT project, will other FIT projects and/or distributed generation projects be allowed to pass it in the queue?

HECO Companies Response:

a. A timeline for completion on an IRS is dependent on several factors including the level of complexity of the proposed interconnection, the type of generating facility involved, its location and the responsiveness of the applicant in providing the necessary information for the study. The cost for such a study is also highly dependent on the complexity of the proposed interconnection.

b. A project will hold its reservation in the queue while its IRS is being conducted. Projects in the queue do not necessarily have to be completed in the order of their listing in the queue. In other words, projects with more straightforward interconnection requirements may end up being completed ahead of those with higher level difficulties even though they may be added to the queue later in time sequence.

SA/HSEA-RS-IR-11
Ref.: Proposed FIT Reliability Standards for the Hawaiian Electric Companies, Exhibit 1, p.1. The HECO Companies quote the Commission's September 25, 2009 D&O regarding the "obligation to refuse to interconnect projects that will substantially compromise reliability" How are the HECO Companies choosing to operationalize the Commission's use of word "substantially" for the purpose of discriminating between projects that will and will not compromise reliability. Please provide any references that help clarify the proposed use definition.

HECO Companies Response:

The Companies' proposed Reliability Standards are presented on page 9 of Exhibit 1. Projects will be assessed based on the four factors including cost, operability, compatibility and reliability. An interpretation of "substantially" includes the impact to customers either in the form of increasing costs or a reduced quality of service. If a project compromises reliability but can be accommodated with economic system modification that have overall grid benefits for all customers, then the project may be more likely to be accommodated and pass to the regulatory process for PUC approval. If a project compromises reliability and subjects the system to further risks and additional costs (e.g., direct competition amongst existing renewable PPAs, impacts system responsiveness), it is less likely that the project would be recommended for regulatory approval. It is anticipated that the proposed Reliability Standards Working Group will play an important role in working with the utilities on this evaluation process.

To assess the impacts of these resources, sufficient time must be allotted to conduct the system level studies as well as local line studies in a more integrated fashion. Built into the process is a re-evaluation and validation with actual system information to track the progress as penetration levels increase. The Companies have recommended a series of studies to be pursued with the intent that likely renewable resources will be best accommodated to meet RPS objectives. Through other initiatives, the Companies are also evaluating new process tools to better manage the level of renewable resources with the existing portfolio of resources. Moving forward, the studies and data tracking efforts will provide input data and a foundation to plan for future resources.

SA/HSEA-RS-IR-12

Ref.: Proposed FIT Reliability Standards for the Hawaiian Electric Companies, Exhibit 1, p.42, the HECO Companies definition for "Reliability Standards."

Please explain how the HECO Companies formulated this definition of reliability standards, including relevant references. If the definition is borrowed from an existing source, please provide specific reference information.

HECO Companies Response:

The discussion for the development of the Companies' description for "Reliability Standards" begins on page 5 and the definition is cited in its entirety on p.9 where the principles are aligned to respective operating criteria (Exhibit 1, p. 9 Figure 1). As noted in Attachment 3, the Hawaiian Electric Companies effectively operate in compliance with general industry accepted reliability standards similar to those adopted by the North American Reliability Corporation (NERC). However the Companies differ considerably from the interconnected grids in North America and thus have developed guiding principles and standards for their respective grids that may not in every instance directly parallel those developed by NERC, FERC or other countries. As stated in the context of their adopted procedures, "NERC reliability standards apply to the reliability planning and reliable operation of the bulk power systems of North America." (NERC Reliability Standards Development Procedure). The Hawaiian Electric Companies have developed standards that apply to the reliability planning and operations of the bulk systems and distributed systems of the islands within their service territories. Many of these criteria were documented in Table 8 of Exhibit 1.

In many instances where inter-tied North American market driven grids may be able to leverage resources to remain within reliability limits, those factors will drive their historical response. The Hawaiian grids do not have the same "safety net" as they are stand alone systems that must maintain adequate resources to balance and manage load to ensure reliable operations as appropriate to the economics of each island system. Operating practices and procedures have evolved based on experience to manage and restore the system respective island grids based on load, resources and conditions. From an operational perspective, interconnection requirements and system level settings reference IEEE, ANSI, IEC and other industry standards for grid tied equipment. For standardizing equipment for interconnection onto the grids, the Companies have leveraged mainland grid codes and further adapted ratings and sizes appropriate for use in Hawaii. These include standardizing industry inverters consistent with the California Energy Commission's approved list, and modeling Rule 14 H with California's Rule 21 governing standard interconnections. Hawaii is also leading the nation on many fronts where standards have not been formulated on the mainland grids as they have not seen the level of variable resource penetration as we have seen here on the islands. With regard to distribution protection devices and standard protection "rules of thumb", the island systems may be the first to set new requirements and standards given DG penetrations levels that are already as high as 60% on the distribution feeders with bi-directional flow characteristics.

To continue improving reliability and engage with all parties, there is significant value as proposed in the Companies' Reliability Standards process to convene a Reliability Standards Working Group which includes the utility, electric users and vested stakeholders to review and develop appropriate standards for reliability as the system continues to change. Moving forward and to improve on the baseline standards, a consistent and transparent methodology was also presented to assess the existing system capability, conduct planning and scenario modeling and implement data monitoring and tracking of system and DG level resources to confirm and validate the levels of impact by renewable resources.

Information thus obtained and reviewed by the parties involved will further the ability of the Hawaii grids to reliably accommodate and operate with diverse resources.

<u>SA/HSEA-RS-IR-13</u>

What is the HECO Companies' plan for paying for interconnection costs at problem feeders in the FIT Program. Please explain in detail under which circumstances these costs (a) will or might be and (b) will not be borne by the utility and the rationale the Companies will use to distinguish between the two circumstances.

<u>HECO Companies Response:</u>

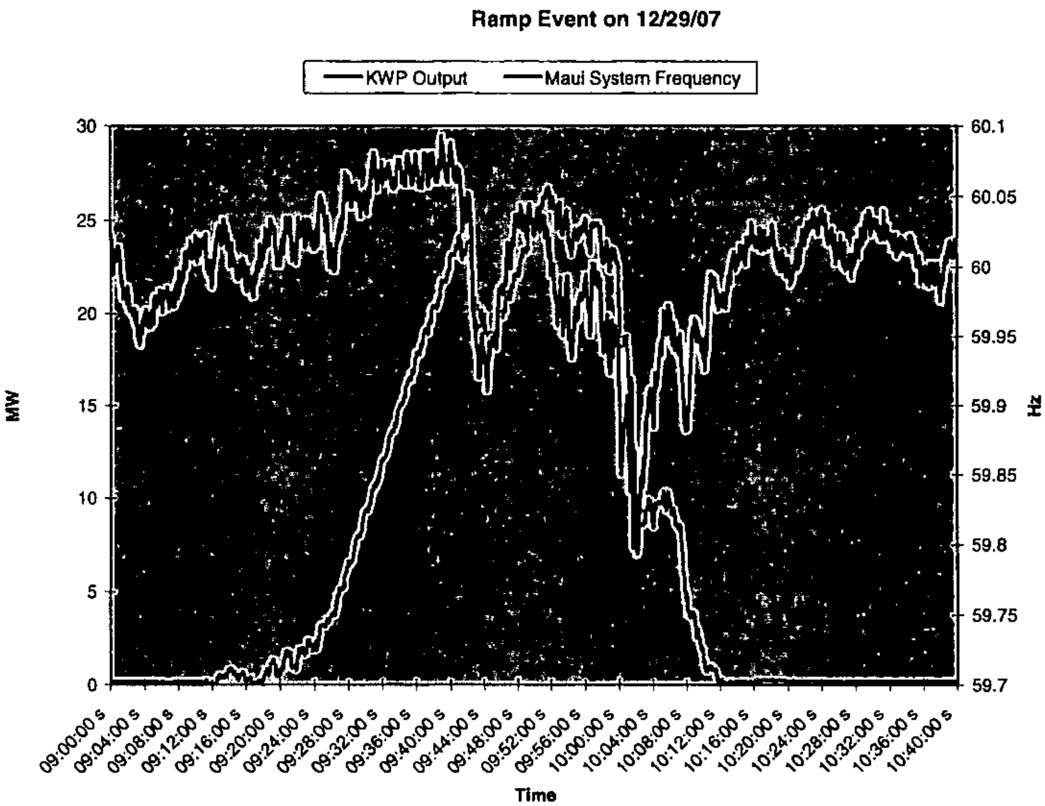
Consistent with the HECO Companies' Tariff Rule 14H, the FIT generator will be responsible for the cost of any Company interconnection facilities associated with the interconnection of its generating facility. FIT pricing will include an allowance for interconnection costs, pegged to that of a "typical" project.

SA/HSEA-RS-IR-14
Please provide any historical incident report or documentation of grid reliability disruption due to intermittent resources over the last five years on the HELCO and MECO grids.

HECO Companies Response:

There are examples provided in Attachment 3 (see Figures 3 and 6) of the HECO Companies Report on Reliability Standards filed February 8, 2010. These are representative of numerous cases of ramp events and variable frequency caused by changes in wind plant output. Figure 7, and the associated text, describes a statistical analysis that was done as part of an EPRI survey of the impact of the variable wind on HELCO system frequency control. The impact of the variable distributed PV is difficult to quantify due to lack of visibility. However several underfrequency events have occurred for levels of generation which in the past, for similar system conditions, generally did not result in underfrequency load shed and we believe that this is consistent with an impact from aggregate loss of DG during low-frequencies. The load-shed scheme was changed due in part to wind-ramp events to avoid prolonged operation at low frequencies (59.3 or less) for more than 20 seconds. See response to BP-HECO-IR-15.

As an example of a ramp event on the Maui system, see the below figure. In this example, the output form the KWP wind facility increases rapidly from 0 MW to approximately 25 MW and then returns to 0 MW over a period of approximately 50 minutes. The increase in the facility's output causes an over frequency event. Conversely, when the KWP facility rapidly reduces its power output the Maui system frequency declines to approximately 59.8 Hz.


Ramp Event on 12/29/07
KWP Output
Maui System Frequency
MW
Hz
Time
30
25
20
15
10
5
0
60.1
60.05
60
59.95
59.9
59.85
59.8
59.75
59.7
09:00:00 s
09:04:00 s
09:08:00 s
09:12:00 s
09:16:00 s
09:20:00 s
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09:48:00 s
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10:08:00 s
10:12:00 s
10:16:00 s
10:20:00 s
10:24:00 s
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10:40:00 s

SA/HSEA-RS-IR-15
Please describe in detail the Reliability Standards that are applied to current projects on the HELCO, MECO and HECO systems. In doing so, please highlight any differences across the three utilities and/or within the three grids of the MECO system. In addition, please specify what standards were applied to guide the interconnection of the following distributed systems:

a. The PV system at HECO's Archer Street facility;
b. Sopogy's NELHA CSP facility;
c. Castle & Cook's Lanai PV; and
d. The CHP system at Manele Bay.

HECO Companies Response:

The Reliability Standards are based upon the operating and reliability principles for system operation, as described in general in Figure 1, and key criteria identified in Table 8 of the Companies' Reliability Standards Report.. In consideration of the impacts of adding aggregate resources such as through the proposed Feed-in-Tariff Mechanism, the aggregate impacts of such resources must be assessed according to the principles identified in Figure 1. The analyses to be performed become more complex depending on penetration levels on the system, as discussed in Figure 9. Historically, with small levels of distributed generation, interconnection studies have focused on the net incremental impact of the single addition which, for most distributed resources, is small relative to the entire system so as to not require thorough system impact analysis. The focus of the distributed generation interconnection studies has been limited to the necessary measures required to interconnect on the distribution circuit. With the proliferation of distributed generation resources such as has occurred on the Big Island, it has brought to the forefront the need to consider and address the system-wide impacts in aggregate in considering the additional distributed variable DG as would be encouraged by FIT. Below is a discussion of the interconnection requirements for particular projects, which were determined primarily on the basis of the size of the project and the implication on the localized circuit. Note that Rule 14H, as written at present, does not provide a trigger point for system-wide analysis of the aggregate impact of numerous small resources. The Lanai example is unique in that the projects are not small relative to the system they connect to and therefore, a broader analysis was required than for the examples on the Big Island and Oahu systems.

a. The PV system planned for the Archer substation has not been installed. However, the evaluation of interconnection for this project was based on Hawaiian Electric's Rule 14H standards as well as the National Electric Code and other safety codes listed in Rule 14H, Appendix I, Section 2.a.

b. The Sopogy project was evaluated by HELCO engineering, and was initially a 500 kW synchronous generator powered by CSP energy. The internal engineering analysis concluded that the system should be equipped with Direct Transfer Trip (DTT) and Watt-VAR real-time data sent to Operations, and load and curtailment control. The Sopogy project eventually replaced the synchronous machine with an induction machine and capacitors to correct a low power factor. The present output is about 100 kW, with plans to scale up to the full thermal capacity later this year.

   The HELCO circuit, Host Park 11, became more complex with the addition of the Koyo USA 700 MW solar PV facility. Nova Energy Specialists was contracted to evaluate the impact of the Koyo project, and the effect of the total planned 1.2 MW generation on a circuit with a minimum daytime load of 1.4 MW. The consultant's analysis concluded there is significant risk of ground fault overvoltage and possibly islanding, and therefore recommended DTT for Koyo.

The interconnection process evaluates the effects of the DG on circuit voltage regulation, fault current impacts, potential for islanding and ground fault overvoltages, impacts to power flow such as export to the transmission system, and the possibility of flicker or harmonics. Data is collected on the circuit being modeled such as impedances of lines and transformers, the load variations over the recent months, the customer system details and the effects on the HELCO distribution and transmission systems are calculated. The complexity of the calculations depends on the percentage of generation to load ratio, which in this case of the Koyo facility was fairly high.

DTT equipment has been installed at both of these generation facilities and HELCO has real-time monitoring of Watt-VAR production, relay-to-relay DTT protection, curtailment control for Sopogy and the ability to trip either facility breaker if necessary.

c. An Interconnection Requirements Study was conducted for the Lanai PV facility by KEMA, Inc. and operating procedures and performance requirements were developed so that the facility could be integrated such that the safety, reliability, and operability of the system were maintained. The IEEE standard 519-1992 was used to specify the harmonic distortion and flicker limits for the facility. Ramp rate limits were developed so that the frequency performance of the system would not be negatively impacted by the facility.

d. An Interconnection Requirements Study (IRS) was conducted for the Manele Bay Combined Heat and Power (CHP) project. KEMA was contracted to perform an IRS as they had previously evaluated the Lanai Station PV project. KEMA's study evaluated the many interdependencies (e.g., voltage control, stability response, transformer winding configuration, ground fault and other protection issues). KEMA performed a protection system analysis for the CHP DG project for both parallel and islanded operation as part of the interconnection study. The KEMA report also offered recommendations based on related IEEE and industry guidelines on islanded operations.

SA/HSEA-RS-IR-16
Regarding reliability standards for transmission level IPP projects.

a. Please provide the Reliability Standards for all existing large scale Independent Power Producers on the transmission level providing firm power;
b. Please provide the Reliability Standards for all existing large scale Independent Power Producers on the transmission level providing non-firm power;

In responding, please indicate when the Reliability Standards for each project were adopted and when they were approved by the Commission.

HECO Companies Response:

Performance requirements are prescribed for Independent Power Producers ("IPP") in their power purchase agreements ("PPA"). Performance requirements are generally described in the operating procedures sections of PPAs. These operating procedures were developed as a result of engineering studies to examine the impact of connecting the IPP to the utility's system and ensure that the IPP's facility can be connected to the utility's system while maintaining the safety, reliability, and operability of the utility's system. Each study takes into account the equipment and characteristics of the specific facility being proposed by the IPP. The Hawaiian Electric Companies have numerous PPAs either approved or pending before the Commission. Non-confidential sections of the PPAs can be made available for viewing upon request.

HECO has the following PPAs with IPPs:

a. Firm Capacity Producers.

1. Kalaeloa Partners. The PPA was approved by the Commission in Decision & Order No. 10122 and 10369 in Docket No. 6378. Refer to Section 3.2B of the PPA.

2. AES Hawaii. The PPA was approved by the Commission in Decision & Order No. 10296, 10448, and 10476 in Docket No. 6177. Refer to Section 3.2B of the PPA.

3. HPOWER. The Firm Capacity Amendment ("FCA") was approved by the Commission in Decision & Order No. 11700 in Docket No. 6983. Refer to Appendices B and D of the FCA.

b. Non-firm or as-available energy producers.

1. Chevron. The PPA was approved by the Commission in Decision & Order No. 10679 in Docket No. 6717. Refer to Appendix B of the PPA.

2. Tesoro. The PPA was approved by the Commission in Decision & Order No. 7872 in Docket No. 5025. Refer to Appendix B of the PPA.

3. Kahuku Wind Power. The PPA and Amendment was submitted to the Commission for approval in Docket No. 2009-0176. Commission approval is pending. Refer to Appendix B of the Amendment.

4. Honua Power. The PPA was submitted to the Commission for approval in Docket No. 2010-0010. Commission approval is pending. Refer to Appendix B of the PPA.

<u>MECO has the following PPAs with IPPs</u>:

a. Firm Capacity Providers

1. HC&S: The PPA was approved by the Commission in Decision & Order No. 10803 and Order No. 10874 in Docket No. 6616. Refer to Section IV of the PPA.

b. Non-firm or as-available energy producers:

1. Kaheawa Wind Power. The PPA was approved by the Commission in D&O No. 21701 in Docket No. 04-0365. Refer to Appendix B of the PPA.

HELCO has the following PPAs with IPPs:

a. Firm Capacity Providers

   1. Puna Geothermal Venture: The Performance Agreement and Fourth Amendment to the Purchase Power Contract were approved by the Commission in Decision & Order No. 14840 in Docket No. 96-0042. Refer to Appendix B of the PPC.

   2. Hamakua Energy Partners: The PPA was approved by the Commission in Decision & Order No. 17077 in Docket No. 98-0013. Refer to Section 3.2B of the PPA.

b. Non-firm or as-available energy producers:

   1. Wailuku River Hydroelectric Power Company, Inc.: The PPA was approved by the Commission in D&O No. 11333 in Docket No. 6956. Refer to Appendix B of the PPA.

   2. Hawi Renewable Development: The PPA was approved by the Commission in D&O No. 20979 in Docket No. 04-0016. Refer to Appendix B of the PPA.

   3. Tawhiri Power LLC (wholly owned subsidiary of Apollo Energy Corporation): The Restated and Amended Power Purchase Contract for As-Available Energy was approved by the Commission in D&O No. 21693 in Docket No. 04-0346. Refer to Appendix B of the RAC.

SA/HSEA-RS-IR-17
Please provide a matrix listing distribution circuits for each utility with current peak loads, minimum load; current firm DG penetration levels, current non-firm DG penetration levels, firm DG pipeline, and non-firm DG pipeline.

HECO Companies Response:

As part of the new CESP framework and as referenced on p 41 of Exhibit 1 of the Reliability Standards Filing, the Hawaiian Electric Companies worked with stakeholder parties and developed an initial rendering of the Locational Value Map (LVM) which effectively contains a listing of many of the distribution circuits around the island and the percent penetration of distributed resources on those circuits based on peak circuit loading. This information is web accessible and users can submit requests via email to further enhance and improve the usability of this resource tool.

As certain circuits may have critical and or sensitive loads including hospitals, banks, military facilities, food warehouses and other critical infrastructure, the Companies have not provided circuit level details including names of distribution substations, actual levels of penetration and exact geographic locations. Through additional discussions with industry representatives, for purposes of providing information on whether a specific project may encounter delays due to the need for detailed utility studies, the Hawaiian Electric Companies devised a color coding representation for the distribution circuits for Oahu, Maui, Hawaii, Molokai and Lanai by percent penetration of DG resources on the circuits. Category ranges of 1 to 5%, 5 to 10%, 10 to 15% and greater than 15% are shown on the current maps but can be modified to show more detailed segmentation. Per the proposed modifications to Rule 14H, circuits above 15% will require a utility interconnection study. Also the LVM does not preclude the formal process to request an interconnection as may be required by programs such as NEM and the SIA process.

This LVM tool provides an updateable, web-enabled resource to regularly updated information pertaining to the circuits. Besides sensitive load concerns, there is concern in making the various distribution circuit loads widely published as 1) they vary continuously throughout the day and with customer use changes and 2) the penetration levels on those circuits can also change quickly depending on the number of DG requests. It is recommended that project developers continue to contact the utilities and follow the processes to request interconnection and obtain specific information for planning projects.

With respect to existing firm DG resources, Exhibit 1 of the Reliability Standards Report, DG baseline tables were provided for Oahu, Maui, Hawaii, Molokai and Lanai (Tables 2 through 6). The baseline information summarized known utility DG penetration levels in kW and in % of system peak as of 2009 by the different type of DG agreement (e.g., NEM, Schedule Q) for firm and non-firm DG generation as of December 2009.

<u>SA/HSEA-RS-IR-18</u>
Exhibit A of the October 2008 Energy Agreement between the HECO Companies included expected levels of installation for the pipeline installations that are under way and projected installations of new PV systems. Why are these generators only now being considered a significant impediment to the interconnection of additional DG on the MECO and HELCO grids?

<u>HECO Response:</u>

Exhibit A to the Energy Agreement sets forth certain Cumulative Target Goals (in MW by year-end) for each of the Hawaiian Electric Companies. The Cumulative Target Goals were developed based upon the best information available at the time the Energy Agreement was drafted and executed. Contrary to the implication contained in the information request, it is not that the specific resources or programs listed in Exhibit A are "now being considered a significant impediment to the interconnection of additional DG on the MECO and HELCO grids." Rather it is the volume and velocity of renewable resources in addition to those identified in Exhibit A that collectively, are raising the concern that MECO and HELCO in particular must proceed responsibly and with care in interconnecting new resources to ensure that they are not inconsistent with the directives contained in the Commission's September 25, 2009 Decision and Order. As just one example of this, Exhibit A to the Energy Agreement identifies a Cumulative Target Goal for NEM resources, by the end of 2010, of 2.2 MW for MECO and 1.3 MW for HELCO. As indicated in the Hawaiian Electric Companies' Report on Reliability Standards filed on February 8, 2010, as of the end of 2009, MECO already has 3.7 MW of NEM resources and HELCO already has 3.4 MW. (See, Report on Reliability Standards at pages 15 and 25)

SA/HSEA-RS-IR-19

The maximum grid-wide penetration renewables on the HELCO system is roughly 50 percent, and on the MECO system it is roughly 15 percent. After excluding the firm renewable power provided by PGV on the HELCO system, what explains the HELCO system's ability to operate reliably with a higher share of renewables?

HECO Companies Response:

HELCO's % variable RE (Existing) is 29% of 2009 system peak, and Maui is at 17.3%. HELCO is experiencing challenges managing this high penetration of variable generation, even more so than MECO.

The analysis contained in Attachment 4 analyzed the MECO system with the existing 30 MW and approximately 42 MW of additional variable wind generation currently under development. When the planned wind additions are considered, it is anticipated that MECO's grid-wide percentage of variable renewables will exceed that of HELCO's

SA/HSEA-RS-IR-20
Please explain how, if at all, the non-coincident nature of disturbances in the generation of geographically distributed PV systems has been factored into the development of the HECO Companies' proposed reliability standards. Please also explain how this differs from the treatment of the generation profiles of concentrated firm resources on these same systems.

HECO Companies Response:

At this time the degree of coincidence between PV systems on the various grids is not known to the degree that it could be included in the analysis. Such information, if available, could be factored into an analysis that is based on general or typical conditions. For system reliability conditions, the "worst-case" scenario would also need to be considered for the particular condition of study (for example, study of aggregate loss of PV would require an understanding of the largest possible degree of correlation so that the boundary condition for the loss is studied). HELCO has initiated a pilot project for monitoring PV and estimating PV production across the Hawaii Island power system as described in Attachment 2. The proposed Reliability Standards Working Group is envisioned to further assist with data gathering.

Even in the absence of data regarding correlation, evaluations were able to draw conclusions based on the existing information. As shown in Attachment 4, even without the addition of any additional distributed variable renewable energy projects, the HELCO and Maui systems will be curtailing renewable energy during on-peak hours for many of the hours of the year, once the planned transmission-connected projects are online. In other words, HELCO and Maui do not have sufficient energy demand at this time to accommodate all the planned renewable energy, in the absence of demand growth. Distributed generation appears as reduction in system demand and will have a measurable impact on those projects already planned. As the distributed variable generation does not have the capability to further displace conventional generation, the addition of these resources would have a minimal effect on increasing renewable energy (in total to the system) while reducing the potential sales for new and existing projects. Further, the analysis done to date on other distributed generation issues shows that even below existing levels of variable distributed generation (based on capacity) there is an impact on the system response, which needs to be understood especially as it applies to the system protection scheme, and underfrequency/under voltage scheme, (but also with consideration of the other issues identified in Attachment 2) so that mitigating measures can be put in place to avoid unacceptable consequences to reliability. Finally, the HELCO and Maui systems are challenged in managing system balance and frequency control with the existing (and new, for the Maui system) wind plants. The impact of variable distributed generation on the system balancing and control needs is not presently known because of the lack of the type of information identified here (correlation, magnitude of changes, etc). However, as the system operator needs to manage the system with these resources, it is important to collect such data so that changes to system operation can be made as necessary. The amount of increase on overall variability is not known, but will be more than exists today; it is the degree of change that is not known.

In response to how the treatment of concentrated transmission-connected resources was handled, for the existing transmission-connected variable resources, the actual amount of production is known from measured data. For existing transmission-connected dispatchable renewable energy, the energy can be scheduled and is available unless the unit is on outage; this makes the planning much easier. Depending on the analysis, maximum capacity or varable capacity may be used to capture the boundary condition for the particular issue. For example, to ensure that the utilities' infrastructure can manage 100% output of variable resources and dispatchable resources it will need to be studied to assess the impact on steady state power flows. For future variable resources and studies of the impact of those resources on variability, the variability information is provided by the developer typically based on field measurements and equipment power conversion characteristics.

SA/HSEA-RS-IR-21
The reference from the FIT D&O (at 44) cited by the HECO Companies appears to be extracted from a more comprehensive directive regarding system reliability that states:

"To address these concerns, the commission will limit additional wind generation projects (up to 100 kW) on the HELCO and MECO systems for purposes of eligibility for the initial FIT. In addition, the commission will reiterate the HECO Companies' continuing obligation to ensure system reliability."

Please explain how this supports the development of a new grid-wide limitation that deals only with DG in the aggregate.

HECO Companies Response:

Details regarding the Hawaiian Electric Companies' development of their proposed reliability standards, including identification of levels of additional resources that may be accepted onto the Companies' systems consistent with the directives and determinations discussed at page 44 of the Commission's September 25, 2009 Decision and Order, are set forth at pages 1-5 of the Companies' Report on Reliability Standards filed on February 8, 2010. The Hawaiian Electric Companies recommend that the proposed Reliability Standards Working Group consider the capability of grids to accommodate new resources, FIT or otherwise, and not only DG in the aggregate

SA/HSEA-RS-IR-22

In proposing the "reliability standards" at 5% of grid-wide peak load for DG, are the HECO Companies concerned with curtailment or with system instability, or both? If both, please explain how the 5% deals with interconnection of system above 5% that would not destabilize the grid but may result in curtailment.

Please explain with specificity how the proposed reliability standards prevent curtailment on transmission level projects?

HECO Companies Response:

The rationale for the proposed initial limits on variable distributed generation is

1) to allow the impact, on a system basis, to be evaluated to ensure that there are not unacceptable reliability impacts for higher penetration levels. Unacceptable reliability impacts would include system instability following faults and contingencies, inability to manage system frequency, and similar conditions and are discussed in Attachment 2 of the HECO Companies' Reliability Standards filed February 8, 2010.

2) To ensure that the addition of variable generation projects encouraged under the FIT Program are replacing energy from conventional fossil resources, rather than displacing renewable energy from new and existing renewable energy providers. This is the "curtailment" or excess energy issue described in Attachment 4 of the HECO Companies' Reliability Standards filed February 8, 2010.

Limiting such variable generation additions does not preclude or prevent curtailment of transmission connected resources. As shown in Attachment 4 of the HECO Companies' Reliability Standards filed February 8, 2010, there are curtailments required today for the HELCO and MECO systems and it is likely that there will be insufficient demand at present levels for the system to absorb the entire amount of planned renewable energy. Further, it is anticipated that such curtailments may become necessary during day-time hours when generators such as solar PV produce energy. However, it is hoped, by imposing appropriate initial limits upon the level of additional variable resources, the impact on existing and new renewable energy providers will be minimized.

SA/HSEA-RS-IR-23
Please list the existing and planned renewable resources referenced on page 4, paragraph 1, sentence 3, of the HECO Companies' February 8, 2010 reliability standards filing, including the anticipated placed in service dates for "planned" resources.

HECO Companies Response:

The existing renewable resources on the MECO grid are 1) the existing renewable distributed generation included in Table 4, 2) HC&S and 3) KWP. The planned renewable resources on the MECO grid are the planned renewable distributed generation included in Table 4 and two additional windfarms.

The existing renewable resources on the HELCO system are 1) the existing renewable distributed generation included in Table 3, 2) Waiau Hydro, 3) Puueo Hydro, 4) Lalamilo Wind Plant, 5) Wailuku River Hydro, 6) Hawi Renewable Development (HRD) Wind Plant, 7) Pakini Nui (also known as Tawhiri or Apollo) Wind Plant, and 8) Puna Geothermal Venture (PGV). The planned renewable resources are the 1) planned renewable distributed generation included in Table 3, 2) 24 MW biomass, and 3) 8 MW geothermal.

SA/HSEA-RS-IR-24

Regarding the "Reliability Standards Working Group" proposed on pages 4-5 of the February 8, 2010 filing, please detail the anticipated timelines for the following steps:

a. Selecting members of the group;
b. Convening meetings(s) of the group;
c. Conducting technical studies of the Companies' grids as a result of the directives of this group;
d. Conducting research on existing literature on these same issues in support of the group's activities;
e. Implementing any suggestions by the group to address the concerns raised by the HECO Companies in the February 8, 2010 filing.

HECO Companies Response:

Please see the HECO Companies' Response to Commission Letter of February 19, 2010, filed February 26, 2010 in this proceeding.

SA/HSEA-RS-IR-25

Regarding "dynamic stability issues" on page 6, paragraph 2 of the HECO Companies' February 8, 2010 filing:

a. Please describe in detail the "significant dynamic stability issues" being encountered on the HELCO and MECO grids due to "distributed PV."
b. Please explain how the proposed reliability standards address these issues.
c. Please explain how the Companies attribute to PV "significant dynamic stability issues" when the "production profile, degree of variability and correlation between sites is not known."
d. Please explain why the capacity factor of the PV systems on the HECO and HELCO grids is not known to the HECO Companies given the location and module specific detail provided to the Companies through the standard interconnect, net metering, etc. agreements.
e. Please present and describe the evidence supporting the HECO Companies' position that DG/distributed PV, rather than (a) larger transmission level resources and/or (b) the technological characteristics of the Companies' grids are responsible for the "significant dynamic stability issues" of concern to the Companies.

HECO Companies Response:

a. The referenced section does not state that "significant dynamic stability issues" are present on the MECO grid due to distributed PV, although if PV is installed with similar characteristics and penetration levels as on the HELCO system, it is anticipated the impacts would be similar. Please see Attachment 2 to the February 8, 2010 filing for a summary of the issues related to distributed generation and Attachment 3 for discussion on some of the issues related to variable generation. In general, the dynamic stability issues from distributed variable PV are due to the impacts on the system's response during faults and contingencies, and on the systems frequency response and control capabilities.

b. Significant dynamic stability issues (existing and/or potential) could be mitigated through implementing appropriate measures determined as a result of analyses and studies conducted by entities such as the proposed Reliability Standards Working Group. This approach will avoid causing significant reliability impacts by allowing for analysis of the impacts, in advance of their occurrence on the system, and implementing the identified mitigation measures prior to or as part of the installation of the distributed variable resources if appropriate.

c. The "significant dynamic stability issues" are not the result of the effect of the variable distributed generation (such as PV) alone, but the aggregate system effects created by all variable and distributed generation on the system. Some issues are specific to distributed generation (such as behavior during disturbances, etc…); others are specific to variable generation. The issues that are related to aggregate loss of distributed generation, for example, can be studied without requiring data on production profile, variability, and correlation between sites. However, it is difficult to quantify the impact of PV on the existing system balancing and control issues due to the absence of telemetered data. In order to further this understanding a project has begun to take field measurements of available solar PV energy and estimate the level and variability of the PV on the HELCO system.

d. Capacity factor is equal to the kWhrs produced over a given time period divided by the product of the number of hours in the given time period and the nameplate capacity (kW) of the facility in question. Because the majority of distributed PV is designed to serve onsite load (on the customer's side of the meter) prior to export, an accurate value for the kWhrs produced by the PV system is not available to the Companies. To state it another way, the Companies' meters only record the net input or output (PV generation – onsite load) for a customer, therefore the PV system gross output is not known.

e. It is not the HECO Companies' position that "significant dynamic stability" issues are attributable to "DG/distributed PV" as opposed to larger transmission level resources and/or the technological characteristics of the Companies' grids. In particular, Attachments 3 and 4 discuss issues at a system level, including for the HELCO system a discussion of the impacts from all generation resources with specific examples from existing variable generation; and further discusses how variable distributed generation will impact the systems. The analysis in Attachment 2 is specific to issues pertaining to distributed generation resources. It should be noted that larger renewable energy resources which provide similar characteristics to conventional generation (dispatch and control by system operator, participation in supplemental frequency control, frequency response, voltage regulation, load following, etc.) can provide beneficial system dynamic stability impacts. The Reliability Standards particularly examined the impacts of additional variable distributed generation on the systems with consideration of existing and planned RE resources.

SA/HSEA-RS-IR-26

Regarding the issue of exported power entering the sub-transmission level or transmission systems (Page 7 of the February 8, 2010 filing):

a. Please explain the reliability impacts that concern the HECO Companies in the event that exported power reaches the sub-transmission or transmission systems.

b. Please specify the incidents and conditions under which this has occurred on any of the HECO Companies' grids.

HECO Companies Response:

a. The sub-transmission systems are radial feeders that feed distribution substations that step the voltage down to the distribution circuits. The sub-transmission and distribution systems are currently designed for one-way power flow from the transmission system to the distribution substations. If enough power is generated on the distribution circuits such that the power flow changes direction and is exported from the distribution to the sub-transmission system, the protection systems on those circuits may not operate property. Also, if large generating facilities are connected to the sub-transmission circuits such that their production uses up all of the capacity of that circuit, additional power flowing from the distribution circuits to the sub-transmission circuit could cause the sub-transmission circuit to overload. Further, if the radial sub-transmission circuit opens (such as for a fault), the aggregate export of the generation on the circuit will be lost to the interconnection which will cause an underfrequency condition on the interconnection. During the fault condition, it must be assured that the distributed generation on the sub-transmission circuit does not form an unintended island which can cause damaging power quality issues to the customers and generation source.

b. The Kahuku Wind Power project on the HECO system is planned to be connected to a sub-transmission system that is connected to transmission via the Wahiawa substation. During low load hours each day, the wind plant will export power to the transmission system if it is operating at full output. This situation was studied in an Interconnection Requirements Study and the appropriate changes will be made to the protection systems on that sub-transmission circuit. The Kahuku Wind Power project is a 30MW facility. The capacity of the line is approximately 50MW. Should another 20MW facility be proposed that connects to that circuit, then export from the distribution system to the sub-transmission system would pose a problem.

On the HELCO system, the Hawi Renewable Development (HRD) wind plant is connected to the 3300 line from Waimea. The size of the project had to be limited to avoid overloading the line and step-down transformer capacities. The project has a transfer trip scheme to open the wind plant breaker when the 3300 line breaker opens to clear a fault on the 3300 line. This results in low-frequency conditions and contributed to underfrequency load-shed in at least one instance.

The impact of the distributed generation, in aggregate, on the transmission system – when the distributed generation is significant – can alter the power system flows and voltages to a significant extent. As the penetration levels of distributed generation become large in a particular area, and on the system as a whole, the impact on the sub transmission and transmission infrastructure, and power system stability and operation, needs to be assessed similar to the interconnection system impact studies conducted today for transmission-interconnected projects. The challenge is that there has not been a trigger to evaluate study of the aggregate impact of distributed resources on the system as a whole, an issue which is recognized by the reliability standards assessments. A further challenge is the difficulty in modeling some of these resources accurately. These are the types of issues that may be identified for study and for solution development by the proposed Reliability Standards Working Group.

SA/HSEA-RS-IR-27
Please explain how, from the ratepayers' perspective, "better cost performance" can be achieved with central station power than DG that functions in a DSM role, such as distributed PV systems interconnected under standard interconnect agreements.

HECO Companies Response:

It is assumed that this is in reference to the statement on page 8 of 43 of Exhibit 1:

"Displacement of production from transmission-side resources which contributes to excess energy problems including curtailment, and may displace energy production by renewable providers with better cost performance and system benefits"....

In this statement, the word "may" is used to indicate that the situation needs to be assessed for each system and each type of generation. In the context of the FIT, the evaluation would be comparing FIT rates, for example, against proposed geothermal and biomass expansions or existing renewable energy providers that would be displaced by the FIT energy.

It is assumed in this response that the question is in reference to load-offsetting, non-export PV on a customer site. In such a case the PV is reducing the demand on the system, by providing on-site generation. Such a system will result in the demand to the power system being the difference between that customer's PV generator and that customer's PV load. Typically this can result, under certain weather conditions, in a demand which is much more variable to the system, as PV can change much more quickly than most types of loads. If the energy source (solar energy) is removed (such as due to a cloud) then the generators on the power system must increase production to supply the net increase in demand from the customer. There are two types of ratepayers to consider. One is the ratepayer who owns that type of system. If that customer who owns and operates a distributed PV system is able to reduce the energy purchased from the utility by an amount whose cost is equal or greater to the total cost of the purchase of the system and the maintenance of the PV system, that customer who has installed the distributed PV system will benefit. However, this does not necessarily benefit the ratepayers on the system as a whole. For the ratepayers on the reminder of the system, there is a cost incurred by the power system operator by providing this backup energy. Further, solar PV will reduce the day-time energy demand for most on-peak hours of the day, but will not be available for peak and therefore the utility needs to retain and provide capacity to manage the evening peak. There may be a small reduction in losses, for some of the time; but it is most likely that the costs associated with the standby services provided by the entire power system result in an overall increase to serve all the customers on the system, except those who are benefiting by the reduction of purchases on their own systems. Further, at high penetration levels of distributed PV, system issues begin to arise which will require additional studies and mitigation measures, which require additional system investments. If a low-cost renewable energy source can be provided on the power system (as a whole), all customers will bear the costs (increases and/or benefits) from the addition of that resource. A holistic view of generation additions on the power system will consider the benefits and costs of numerous distributed PV projects owned by individual customers in comparison to the benefits and costs of renewable energy projects on the interconnection in assessing the optimal generation mix.

SA/HSEA-RS-IR-28

Please explain in detail the ongoing frequency concerns presented by distributed PV with under-frequency trip setting at 57 Hz for the HELCO system.

HECO Companies Response:

Distributed PV installed with a trip setting at 57 Hz will remain connected through low-frequencies and it is hoped, should not exacerbate frequency disturbances by tripping offline during frequencies of 59.3 Hz (as in the standard IEEE 1547 settings). However, as illustrated in Table 3, there is 4.4 MW of DG, most of which is PV, for which the settings remain at 59.3 Hz, with a few additional planned projects bringing this to about 4.5 MW. This amount of DG has affected the underfrequency load-shed scheme. As described in Attachment 2, aggregate loss of DG due to nuisance trips due to undervoltages (which occur during faults and system upsets) remains a concern. Further, the HECO Companies need to ensure that the modified settings perform as expected in the field, as expanded ride-through is not in use on many systems. For these reasons, it is recommended that an analysis be conducted to review the effect of the existing DG, reflecting the modified ride-through settings for voltage and frequency where they exist, on the underfrequency load-shed and undervoltage load scheme schemes. This study would help identify the necessary under-voltage and under-frequency ride through, and/or any modifications to the schemes, to protect the system for existing and future distributed generation. The study completed to date indicates that reliability is affected by the existing level of DG with the standard settings, and the study only examined the impact from underfrequency tripping.

SA/HSEA-RS-IR-29

Please state and explain, to the closest reasonable numerical approximation, the daytime relationship between distributed renewable resources and grid-wide frequency changes taking an instantaneous loss of 10 MW loss of DG as a benchmark. That is, what is the frequency impact in Hz of the loss of 10 MW of DG of the HELCO grid?

HECO Companies Response:

HELCO's system frequency bias is a calculated ratio that reflects a steady-state system imbalance (measured in MW) to the change in frequency (measured as .1 Hz). The calculated value for the HELCO frequency bias can change throughout the day depending upon the types of generation online and the system load. Currently, HELCO has a typical daytime frequency bias of 2MW/.1Hz. While the frequency bias could provide some insight to the effect on frequency for the instantaneous loss of 10MW as being approximately 1/2 Hertz, it would underestimate the effect. This is because the frequency bias is based on the steady state droop characteristics of the governors, and the actual frequency excursion will be greater (see "HELCO Maximum Penetration of Distributed Generation Study" conducted by EPS and submitted under Docket 2008-0273 on 8/14/09.) The steady state frequency will be significantly higher.

The actual impact on system frequency of an instantaneous loss of 10MW of DG would need to be determined by a study that would incorporate the transient underfrequency response of the units and other factors that could affect frequency from an instantaneous loss of 10MW. Other factors that would impact frequency from a loss of 10MW would include the frequency at the time of losing 10MW, the system load and the generation on-line at the time of the loss, and the amount of additional system losses in the transmission/distribution circuits. It can be stated that, based on review of underfrequency events in the past year, a loss of 10 MW of distributed generation could result in underfrequency load-shedding under typical system operating conditions today and the present underfrequency load-shed scheme, either through loss of the instantaneous 58.8 block or loss of the delayed 59.3 Hz block.

SA/HSEA-RS-IR-30
Please explain in detail the ongoing frequency concerns presented by distributed PV with under-frequency trip setting at 58 Hz for the MECO system.

HECO Companies Response:

The current Rule 14H states that the inverter design shall comply with the requirements of IEEE Std 1547. IEEE Standard 1547-2003 is a standard for interconnecting distributed resources with electric power systems. In the IEEE Standard 1547-2003, the under-frequency trip settings for DG systems less than or equal to 30kW is defined as <59.3Hz with a clearing time of 0.16 seconds. This frequency trip setting for DG systems is higher than the under-frequency trip settings defined in the MECO under-frequency load shed scheme. The effect of this difference in trip settings can lead to the loss of distributed generation on the system at a time when more generation is needed to correct the system frequency. Also, the differences in trip settings can cause an increase in system load due to DG systems that were feeding internal loads and export power tripping off-line and the utility system automatically picking the additional customer load at a time when less system load is needed to correct the system frequency. Both instances of losing distributed generation and increasing system load create instability that can affect the system reliability.

DG systems with a capacity greater than 30kW with factory installed under-frequency trip settings can create the same instabilities and system reliability issues as the 30kW and lesser DG systems because the default settings are usually identical. The IEEE Standard 1547-2003 does allow the under-frequency trip settings for DG systems greater than 30kW to be adjustable from <59.8 to 57.0 Hz with a clearing time ranging from 300 to 0.16 seconds. MECO is currently requesting existing DG systems greater than 30kW to modify the under-frequency trip settings to provide better under-frequency ride through capabilities. The degree to which this change will perform as expected and be effective at mitigating the loss of DG during underfrequency events still needs to be evaluated, as expanded ride-through is not in use on many systems.

SA/HSEA-RS-IR-31
Please state and explain, to the closest reasonable numerical approximation, the daytime relationship between distributed renewable resources and grid-wide frequency changes taking an instantaneous loss of 10 MW loss of DG as a benchmark. That is, what is the frequency impact in Hz of the loss of 10 MW of DG of the MECO grid?

HECO Companies Response:

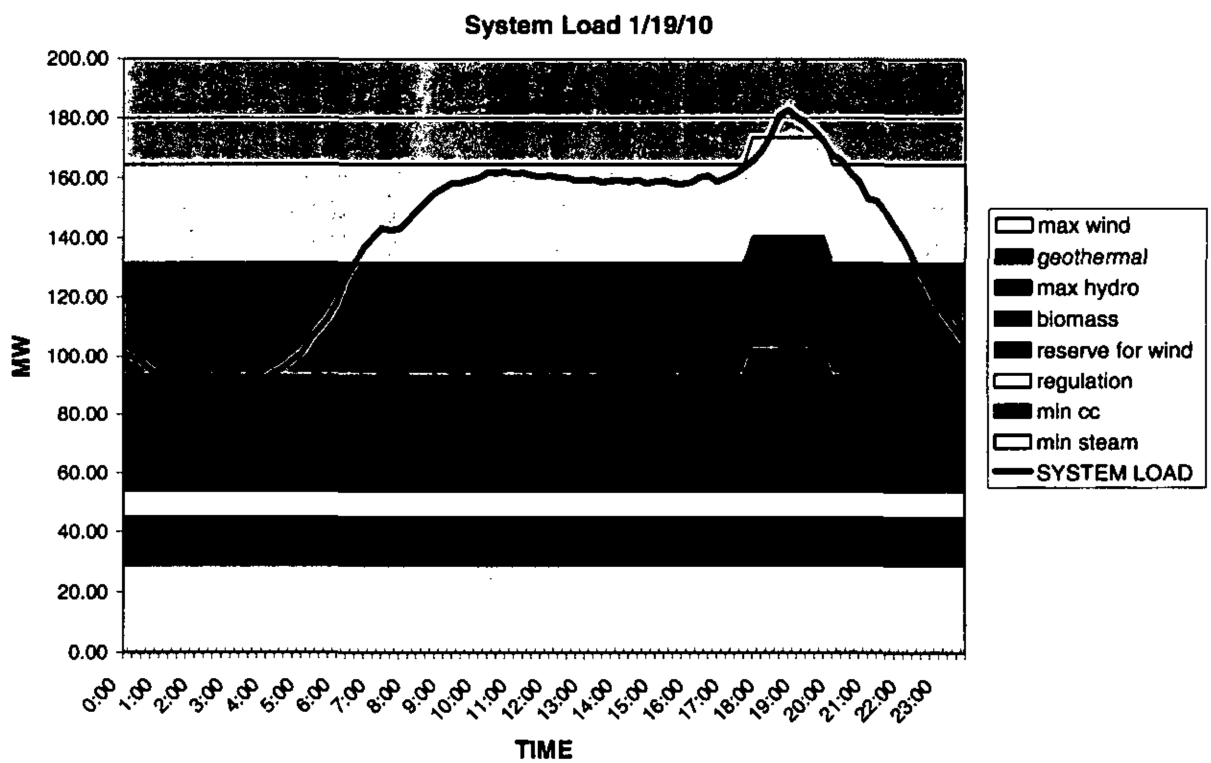
MECO's frequency bias is a calculated ratio that reflects a steady-state system imbalance (measured in MW) to the change in frequency (measured as .1 Hz). The calculated value for the MECO frequency bias can change throughout the day depending upon the types of generation online and the system load. Currently, MECO has a frequency bias that will range from 2MW/.1Hz to 1.5MW/.1Hz with a current typical daytime frequency of 2MW/.1Hz. While the frequency bias could provide some insight to the effect on frequency for the instantaneous loss of 10MW, it would not be a reasonable benchmark. The frequency bias is based on the steady state droop characteristics of the governors, and the actual frequency excursion will be greater (see "HELCO Maximum Penetration of Distributed Generation Study" conducted by EPS and submitted under Docket 2008-0273 on 8/14/09.)

The actual impact on system frequency of an instantaneous loss of 10MW of DG would need to be determined by a study that would incorporate the transient underfrequency response of the units and other factors that could affect frequency from an instantaneous loss of 10MW. Other factors that would impact frequency from a loss of 10MW would include the frequency at the time of losing 10MW, the system load and the generation on-line at the time of the loss, and the amount of additional system losses in the transmission/distribution circuits.

SA/HSEA-RS-IR-32
Please provide a version of Figure 2 "System Load 1/19/10" in which the legend and axis labels are legible.

HECO Companies Response:

Following is Figure 2 from Exhibit 1 of the HECO Companies Report on Reliability Standards filed February 8, 2010 ("Reliability Standards"). This same figure is shown in Attachment 4 of the HECO Companies' Reliability Standards.



SA/HSEA-RS-IR-33
Please describe with specificity the "mitigation measures" referenced on page 19, paragraph 3 of the February 8th filing, including their nature, costs and deployment timelines.

HECO Companies Response:

Please see the HECO Companies' Response to Commission Letter of February 19, 2010 filed February 26, 2010 in this proceeding. The proposed Reliability Standards Working Group and Technical Support Group will oversee studies to quickly identify appropriate mitigation measures, at which time their associated costs and deployment timelines will be determined.

SA/HSEA-RS-IR-34

Please list the number of incidents and total number of hours that existing renewable resources have been curtailed between the hours of 9:00 AM and 4:00 PM from January 2005 through January 2010 on the HELCO system. Please provide incident reports and/or other forms of documentation to support these data.

HECO Companies Response:

Please see the response to BP-HECO-18.

A general statement can be made that excess energy curtailments during these years generally occur during off-peak hours. On-peak curtailments for the hours referenced, occurred infrequently as necessary due to transmission constraints or system impacts for which the most effective control was curtailment of that particular resource.

SA/HSEA-RS-IR-35
Please list the number of incidents and total number of hours that existing renewable resources have been curtailed between the hours of 9:00 AM and 4:00 PM from January 2005 through January 2010 on the MECO system. Please provide incident reports and/or other forms of documentation to support these data.

HECO Companies Response:

Please see the response to BP-HECO-18.

A general statement can be made that excess energy curtailments during these years generally occur during off-peak hours. On-peak curtailments occur infrequently and are applied as necessary due to transmission constraints or system impacts for which the most effective control is curtailment of that particular resource. This situation is expected to change with the addition of two wind plants, which will likely require curtailments of excess energy into the period in question as illustrated in Attachment 4.

Response to

Tawhiri's

Information Requests

<u>TPL-HECO-IR-1</u>
You state on Page 4 of the Reliability Report ("Report") that "Due primarily to the high level of existing and planned renewable resource penetration on the MECO and HELCO systems, the studies indicate that there is minimal to no room at this time to accommodate additional renewable resources (FIT or otherwise) without significant curtailment of either existing or planned renewable resources, or a threat to system reliability." Please quantify what do you mean by "significant curtailment"?

<u>HECO Companies Response:</u>

The amount of curtailment that is determined to be "significant" needs to be evaluated on a case by case basis. It can be stated that under certain circumstances, and assuming minimal growth in demand, any additional production of must-take renewable energy (such as distributed PV) on the system would displace an equivalent amount of renewable generation from other (new or existing) renewable energy providers during daytime hours on the HELCO and Maui systems. This is illustrated in Attachment 4 to the Companies' Reliability Standards Report in the stack charts which illustrate the future 24-hour generation production compared with present demand levels.

TPL-HECO-IR-2

You also state on Page 4 of the Report that "the integration of FIT resources on the HELCO and MECO systems may have to be temporarily deferred until additional studies can be performed and/or infrastructure developed":

A. How much time will it take to perform the "additional studies" for the Big Island:
B. When you say "and/or" do you mean the infrastructure can be developed without undertaking the additional studies?
C. How much time will it take to develop the needed infrastructure improvement?
D. Please describe the type of infrastructure upgrades that would be needed to allow inte0grating FIT resources into the HELCO system:
E. What will be the potential cost of such upgrades?

HECO Companies Response:

A. Please see the Companies' response to BP-HECO-IR-11.

B. See response to subpart A.

C. See response to subpart A.

D. See response subpart A.

E. See response subpart A.

TPL-HECO-IR-3

You advocate on Page 4 of the Report "convening a Reliability Standards Working Group that would serve as an open and transparent forum to allow stakeholders and technical experts an opportunity to regularly review and provide input to the studies that are described in this report and the attachments thereto". You also recommend that the Reliability Standards Working Group not be restricted to the FIT parties but include representatives with a range of technical expertise (e.g., the United States Department of Energy, Electric Power Research Institute ("EPRI") and the Hawaii Natural Energy Institute).

A. Are you implying that the existing IPPs would have to be FIT parties to be able to participate in the proposed Working Group?

B. Is HECO willing to forward to the Commission competing proposals for the structure, conduct and scope of activities of the Working Group?

HECO Companies Response:

A. Please see the HECO Companies Response to Commission Letter of February 19, 2010, filed February 26, 2010 in this proceeding.

B. The HECO Companies' February 26, 2010 filing is a proposed framework for the Working Group. The FIT parties have agreed that comments on the Working Group framework will be filed to the Commission on March 15, 2010.

TPL-HECO-IR-4

On Page 5 of the Report you make the assertion that "as this process will be ongoing and require some level of flexibility to respond to changing system conditions, the Working Group process should be organized and facilitated separately from the Companies' Clean Energy Scenario Planning process".

A. Which of these two processes drives the other?
B. How do you propose to consolidate the results of these two processes?
C. Given the limited resources of many stake holders, would you consider merging the two processes?

HECO Companies Response:

A. Neither process will drive the other. Instead, information from the most recent Clean Energy Scenario Planning ("CESP") process and any more current information about the system, such as but not limited to current additions of NEM installations, current additions of "no-sale" Rule 14H additions, and forecasts for future load growth, can be used by the Reliability Standards Working Group at a point in time in which additional analyses and technical studies is appropriate. Likewise, information from the Reliability Standards Working Group, including results of technical studies on the level of distribution connected and variable renewable generation that can be integrated into each electric system, will be one of many inputs and factors to be used in the CESP process.

B. There would be no "consolidation" of results. Rather, the most current information from each will be used and factored into the other process. Please see the response to subpart "A" above.

C. No. The CESP process is a periodic (3 year cycle), broader resource planning process which takes into consideration future uncertainties to develop strategic guidance on long-range resource planning and to develop a 5-year action plan on demand-side, supply-side and transmission system requirements. In contrast, the Reliability Standards Working Group is focused on reviewing system studies and evaluations specific to the issue of how much distribution connected and variable renewable generation that can be integrated onto each electric system. Given the two different purposes of these two processes, the Companies do not believe that merging these two process will achieve the intended goals of the Reliability Standards Working Group or the CESP process in an efficient or effective manner.

TPL-HECO-IR-5

You assert on Page 6 of the Report that with the existing high levels of distributed generation (DG) penetration of the HELCO system "significant dynamic stability effects on the power system are already being encountered".

A. Please quantify what you mean by "significant".

B. Your statement implies the observed "significant dynamic stability effects" have been separately evaluated from the effects often attributed to the renewable resources interconnected on the transmission side. Is this correct? If not please explain how you reached the aforementioned assertion.

HECO Companies Response:

A. The detailed descriptions of the system impacts of variable and distributed generation are described in Attachments 2 and 3 to Exhibit 1 of the Companies' Reliability Standards Report. Significant means that the performance of the system has been measurably affected, and in particular, system frequency control cannot be maintained to target ranges and deviations into emergency regions are occurring; and the system response to loss of generation events is affected so that additional underfrequency outages are likely. Details are contained in the Attachments.

B. Some impacts are additive, such as the contribution of variable distributed generation on overall system balancing and frequency control issues being additive to those created by the transmission-connected resources. In Attachment 3, the effect of variable distributed system balancing and frequency control is discussed (see paragraph titled "Impact of Distributed PV" in Attachment 3, page 14). Some issues are particular to distributed generation. Attachment 2 discusses the issues specific to distributed generation.

TPL-HECO-IR-6
Page 16 of the Report indicates that the total capacity of existing and planned DG on the HELCO system amounts to 17.1 MWs whereas the PV portion is 14.4 MWs. Please specify what types of generation technology account for the 2.7 MWs difference.

HECO Companies Response:

As stated on page 16, "nearly 14.4 MW will be PV, with another .36 of wind and hydroelectric".

The remainder, beyond the .36 MW which is wind and hydroelectric, is 2.345 MW of diesel and propane fired generation, as shown in Table 3 (fourth column).

TPL-HECO-IR-7

On Page 17 of the Report you state "HELCO has taken many actions to mitigate the impacts of the variable wind generation of frequency control, including modification of its AGC program and parameters". Please describe the:

A. AGC modifications that HELCO made; and

B. Other actions that HELCO undertook.

HECO Companies Response:

A. A more detailed discussion of the changes made to AGC is provided in Attachment 3, in the section titled "Wind Impacts" beginning on page 11. Numerous algorithm and parameter changes were made. The purpose of the majority of the algorithm changes was to dampen the AGC response to wind-induced frequency errors, to avoid exacerbation of frequency error. Changes were also made to improve the individual unit control response, such as modeling the non-linear response of generating units across their dispatch range to a given raise/lower signal and improve the dynamic frequency bias calculation and the calculation of the frequency effect on individual unit feedback values for inclusion in control actions. Changes were made to area control parameters, to similarly avoid over-correction for errors induced by wind fluctuations. A significant change that had to be made was the modification of the no-control dead band as discussed on page 13. The allocation of reserves had to be changed to force allocation across several units, in order to ensure that the regulating units (in aggregate) could respond to frequency deviations caused by wind power changes.

B. In addition to the modification of AGC, HELCO has undertaken many actions including the following: modified reserve policies, upgraded control systems on generating units to improve dispatchable range and ramping capability, projects to improve unit governor droop response, applications to modify environmental permitting to account for unit response to wind-related frequency variations, working with new and existing IPP to improve ramping capabilities and provide droop response, including consideration of the need for droop and AGC frequency control in the design of the combined cycle Keahole facility, and work with NREL on wind forecasting research for targeted forecasting of near-term wind ramp conditions.

TPL-HECO-IR-8
In Page 17 of the Report you assert that "during periods of high variable resource output, in the absence of significant load growth, it will be difficult for the HELCO system to accommodate future and existing renewable energy resources even if all dispatchable conventional generation operates nearly twenty four hours a day at near minimum". Are you saying that even during the daily peak demand hours, curtailment would occur under the circumstances quoted above?

HECO Companies Response:

Yes, under circumstances as described above, the HELCO system cannot accommodate all possible renewable energy resources during daily peak demand hours. The particular resource(s) to be "curtailed" may include variable must-take providers, a reduction in purchase from certain dispatchable renewable energy providers, or a combination of both depending on the particular circumstances.

TPL-HECO-IR-9
Regarding Figure 2 on Page 18 of the Report, please provide a table specifying the makeup (resource/unit names and MWs) for each of the following categories of generation resources:
A. Maximum output from dispatchable renewable energy sources;
B. Maximum variable renewable energy:
C. Minimum must-run dispatchable generation;
D. Minimum CC;
E. Minimum Steam;
F. Regulation; and
G. Minimum Reserve down.

HECO Companies Response:

The assumptions used in the graph, and a similar one which does not assume firm capacity backup is required for wind, are described in more detail in Attachment 4 beginning on page 6. It should be noted that this graph is illustrative of future operating scenarios and is subject to change based on the constraints and other issues discussed in Attachment 4.

A. 52 MW (24 MW biomass, 38 MW from geothermal)

B. Maximum variable renewable energy (33 MW wind, 15.5 MW hydro) comprised of Tawhiri, HRD, Lalamilo wind farms and Wailuku, Puueo and Waiau hydro.

C. This is not a category on the graph. However it would be comprised of Minimum CC + Minimum Steam

D. Minimum CC is 16 MW during most hours. For the graph in question, another 9 MW is added for a second train during peak hours. The minimum CC for the majority of the day (16 MW) is the combination of the HEP and Keahole units in combined cycle, single train. The second train adds 9 MW and could be from either unit but would likely be

Keahole if dispatch order is similar to today. Figure 5 in attachment 4 illustrates the same 24 hour curve if it is not necessary to backup the high variable production with firm dispatchable reserve during peak hours.

E. Minimum steam is 29 MW from Puna, Hill 5, and Hill 6 steam units.

F. Regulation is the minimum amount of down reserve. The present operational policy of 9 MW reserve down is assumed in this graph, but as described in Attachment 4, may need to be reassessed with dispatchable units operating near minimums during on-peak hours.

G. See answer F.

TPL-HECO-IR-10

Regarding Figure 2 on Page 18 of the Report, please specify whether:

A. The Geothermal Category includes the 8-MWs PGV expansion that is under consideration?

B. The Biomass Category includes the contemplated expansion?

HECO Companies Response:

A. Yes. The assumptions used in the graph, and a similar one which does not assume firm capacity backup is required for wind, are described in more detail in Attachment 4 beginning on page 6.

B. Yes.

TPL-HECO-IR-11
Does the reference to the "shaded area" in Figure 2 of the Report pertain to the gray area at the top of the graph? If so, are you saying that wind generation would be curtailed most of the day (essentially > 23 hours) during peak wind production episodes?

HECO Companies Response:

The colored areas above the dark line indicate periods of excess energy. They illustrate that under conditions of high variable generation production, with consideration of future resources, the HELCO system cannot accommodate all possible renewable energy resources during daily peak demand hours. The order in which the biomass, hydro, geothermal, and wind are portrayed in this graph is for illustrative purposes with respect to potential energy from renewable resources. The particular resource(s) to be "curtailed" may vary between must-take providers, a reduction in purchase from dispatchable renewable energy providers, or a combination of both depending on the particular circumstances.

TPL-HECO-IR-12

The Report states on Page 19 that "In light of the existing grid constraints and the urgency of the situation, HELCO proposes to defer additional variable DG interconnection requests on the HELCO system, including standard interconnection agreement and NEM requests, until appropriate mitigation measures are identified and employed to appropriately integrate additional variable DG:. It further says "HELCO also plans to defer entering into Bi-lateral PPA negotiations: and "Bi-lateral negotiation cannot be guaranteed, and in fact can only proceed if such additional studies show that projects would not result in significant reliability impacts, significant curtailment of existing or planned renewable generation, or unreasonable costs to ratepayers". In light of these statements, does HELCO/HECO intend to suspend/delay entering into bi-lateral contracts that will add significant geothermal and biomass generating capacity to the system?

HECO Companies Response:

HELCO does not intend to suspend or delay negotiations with the proposed geothermal and biomass projects referred to. This is due at least in part to the firm, renewable, dispatchable power which these facilities can provide and which can contribute to the ability of the grid to accept a greater level of variable renewable resources, as well as the resulting reduction in the use of fossil fuels on the island. HELCO needs to proceed cautiously when considering renewable energy projects which would result in the displacement of other renewable energy projects, or which would contribute to existing reliability concerns.

TPL-HECO-IR-13

On Page 15 of Attachment 4, the Report states that "HELCO has formal agreements in place to procure additional RE in the next two to three years, consisting of 8 MW of geothermal and approximately 24 MW of biomass energy. These resources will be dispatchable and the energy therefore available on demand except during outages and durations". Please respond the following:

A. Please provide a copy of the aforementioned agreements.

B. Please indicate whether HELCO/HECO is planning to defer procuring the amounts of energy specified in said agreements?

C. If it is not possible to provide a copy of each agreement, please answer the following:
   - i. When is the planned on-line date for each facility?
   - ii. Will energy delivery from the new resources be curtailed before curtailing production from any prior renewable energy resources (i.e. ones with earlier on-line dates)?
   - iii. Will the new resources be compensated as Qualifying Facilities (i.e., on the basis of the posted avoided costs of generation of HELCO)?
   - iv. Will output from the new resources be rolled into the HELCO avoided cost determination methodology as QFs-in only or as both QFs-in and QFs-out?
   - v. Will the new resources be compensated for capacity value and/or ancillary services?
   - vi. Did you evaluate the curtailment impacts of adding the new resources on existing generators?
   - vii. Did you evaluate the revenue impacts of adding the new resources on existing generators?

HECO Companies Response:

A. The Agreements being referenced are confidential until the actual Power Purchase Agreement negotiations are completed and therefore cannot be provided at this time.

B. HELCO does not plan to defer procuring the planned biomass and geothermal projects. It is anticipated that these projects will provide cost and reliability benefits while increasing renewable energy on the HELCO system.

C. The information being requested is part of the Power Purchase Agreement negotiations and cannot be provided at this time. (See response to subpart A.)

Response to

Zero Emissions Leasing LLC's

Information Requests

ZE-IR-107

For each utility electric system on the islands of Oahu, Hawaii, Maui, Molokai and Lanai:

a. Identify, by name, generation type and generating capacity, all generating facilities from which the delivery of electricity to the utility electric system can be reduced or curtailed by the utility during a 24 hour period.

b. Please state the order in which delivery of electricity from the generating facilities identified in your response to part a. can be or is reduced or curtailed by the utility during a 24 hour period;

c. For each of the generating facilities identified in your response to part a. please state:

   1. the amount in kilowatt-hours of electricity, by which deliveries of electricity from that generating facility to the utility electric system can be reduced or curtailed by the utility during a 24-hour period; and

   2. the amount, in kilowatt-hours of electricity, by which deliveries of electricity from that generating facility to the utility electric system are being reduced or curtailed during a 24-hour period.

d. For each of the generating facilities identified in your response to part a. that does not generate electricity from hydropower, solar radiation, wind, geothermal, biogas, or biomass (a "non-renewable generating facility"), please state how much electricity generation, in kilowatt-hours of electricity from the following types of generating facilities:

   1. in-line hydropower generating facilities

   2. photovoltaic generating facilities

   3. concentrating solar generating facilities or

   4. onshore wind generating facilities

   considering each such type in the aggregate could be added or delivered to utility electric system, without compromising the reliability of the utility electric system, by displacing, reducing or curtailing electricity generation from such non-renewable generating facility.

HECO Response:

a. For Oahu, please refer to the table on pages 5 and 6 of this response. The table identifies by name, generation type and generating capacity those generating facilities, utility and non-utility, that deliver electricity to the Hawaiian Electric Company, Inc. ("HECO"), grid on Oahu.

All of the HECO-owned units, except for the Distributed Generation ("DG") sets, are subject to dispatch control by HECO, where their outputs can be controlled from moment-to-moment. Those HECO-owned units that are designated as peaking or cycling duty, except for the DG sets, may be turned on and off daily, depending on system demand. The DG sets are ramped up to full load when they are turned on. These small units are not operated at part loads.

The HECO-owned units that are designated as baseload duty operate 24 hours a day and are subject to dispatch control by HECO. Their outputs can vary, depending on system demand, and the outputs at which the units operate are determined through economic dispatch by HECO's Energy Management System ("EMS"). Their outputs can be reduced to their operating minimum ratings, but the units are not turned off, except for planned or forced outages. Typically, during light loading conditions, the baseload units are operated somewhat above their operating minimum ratings to allow for potential situations where load may be suddenly lost from the system and the generating units must reduce their outputs to maintain the balance between supply and demand.

The AES Hawaii and Kalaeloa Partners, L.P. units are non-utility firm capacity units that operate in baseload duty (i.e., 24 hours a day). These units are subject to economic dispatch control by HECO's EMS. The outputs of these facilities can be reduced to achieve economic allocation of load among all operating units, but their outputs cannot be reduced below their contract minimum ratings.

The City and County H-Power waste-to-energy facility provides 46 MW of firm power during weekday on-peak periods (7 am to 9 pm), where, in general, it provides 46 MW to the HECO grid during weekday on-peak periods, 40 MW (or more, if there are no system constraints, such as light loading) during weekday off-peak (9 pm to 7 am) December through May periods, and 25 MW (or more, if there are no system constraints, such as light loading) during the weekend and holiday off-peak December through May periods. HECO cannot reduce or curtail the output of this facility below these levels, unless there are conditions/constraints, such as light loading or a transmission line outage. For the other periods, there are no specified amounts of power that HECO must take from H-POWER.

HECO also purchases energy from two non-utility, non-firm power producers on an as-available basis. HECO has a contractual obligation to accept the energy made available by these two facilities. Therefore, HECO cannot reduce or curtail the outputs of these facilities, unless there are system constraints, such as light loading or a transmission line outage.

b. The order in which generation at each facility is reduced by the utility is determined by economic dispatch so that the units with the largest incremental cost is reduced first with other units following in sequence until such time that the output of the generating units match the load at that time and the required spinning reserves are met. Currently, the mix of generating units include HECO's generators at the Kahe, Waiau, and Honolulu Power Plants and the independent power producers, AES, Kalaeloa and H-Power. The AES, Kalaeloa, and H-Power units are base loaded, therefore they are must run units. The Kahe units 1 to 6 and Waiau 7 and 8 are also base load units and these are additional must run units. The amount of output that these units can be reduced is based on several factors including but not limited to, the system load, generating units on maintenance, forced outage conditions and temporary derates of generating units. Other as available resources such as net energy metering photovoltaic units that are not under HECO dispatch will impact the amount of load to be served. Because there may be several different combinations of these factors and as these conditions change HECO is not able to provide the amounts by which energy can be curtailed during a 24 hour period.

c. See response to subpart b above.

d. See response to subpart b above.

Hawaiian Electric Company, Inc. Firm Capacity Generating Units					
Unit	Type	Duty	Fuel Type	Operating Minimum MW-Net	Normal Top Load MW-Net
Honolulu 8	Steam	Cycling	LSFO	22	53
Honolulu 9	Steam	Cycling	LSFO	22	54
Kahe 1	Steam	Baseload	LSFO	33	82
Kahe 2	Steam	Baseload	LSFO	33	82
Kahe 3	Steam	Baseload	LSFO	32	86
Kahe 4	Steam	Baseload	LSFO	32	85
Kahe 5	Steam	Baseload	LSFO	51	134
Kahe 6	Steam	Baseload	LSFO	50	134
Waiau 3	Steam	Cycling	LSFO	22	47
Waiau 4	Steam	Cycling	LSFO	22	47
Waiau 5	Steam	Cycling	LSFO	23	55
Waiau 6	Steam	Cycling	LSFO	23	54
Waiau 7	Steam	Baseload	LSFO	33	83
Waiau 8	Steam	Baseload	LSFO	33	86
Waiau 9	Combustion Turbine	Peaking	Diesel	6	53
Waiau 10	Combustion Turbine	Peaking	Diesel	6	50
CIP CT-1	Combustion Turbine	Peaking	Biodiesel	39	113
DG Set 1	Diesel Engines	Peaking	Diesel		10
DG Set 2	Diesel Engines	Peaking	Diesel		10
DG Set 3	Diesel Engines	Peaking	Diesel		10
				Total HECO-Owned Firm Capacity	1,328

Oahu Non-Utility Firm Capacity Generating Units					
Unit	Type	Duty	Fuel Type	Contract Minimum MW-Net	Contract Maximum MW-Net
AES Hawaii	Steam	Baseload	Coal	63	180
Kalaeloa Partners, L.P.	Steam	Baseload	LSFO	65	208
H-Power	RDF-Fired Steam	Baseload	Refuse Derived Fuel	25	46
				Total Non-Utility Firm Capacity	434

Non-Utility Non-Firm (As-Available) Generating Units					
Unit	Type	Duty	Fuel Type	Contract Minimum MW-Net	Contract Maximum MW-Net
Chevron U.S.A.	Combustion Turbine	As-Available	Refinery Gas / Naphtha	--	9.6
Tesoro Hawaii Corporation	Combustion Turbine	As-Available	Refinery Gas / Naphtha	--	18.5
		Total Utility Non-Firm Nameplate			28.1

Notes:

1. LSFO = Low Sulfur Fuel Oil.
2. Baseload duty means the unit runs 24 hours a day. The unit may follow load.
3. Cycling duty means the unit is turned on in the morning and turned off in the evening. The unit may also follow load.
4. Peaking duty means that the unit is turned on in the late afternoon to serve the evening peak and is turned off thereafter. The unit may also be turned on to provide spinning reserve.
5. Firm capacity means that the unit can provide a specific amount of power (in MW) at specific times to meet system needs.
6. Non-firm or as-available generation means the utility cannot rely on a specific amount of power at specific times to meet system needs. In general, the utility has an obligation to accept as-available energy that is made available by as-available energy producers.

ZE-IR-107

For each utility electric system on the islands of Oahu, Hawaii, Maui, Molokai and Lanai:

(a) identify, by name, generation type and generating capacity, all generating facilities from which the delivery of electricity to the utility electric system can be reduced or curtailed by the utility during a 24-hour period;

(b) please state the order in which delivery of electricity from the generating facilities identified in you response to part (a) can be or is reduced or curtailed by the utility during a 24-hour period;

(c) for each of the generating facilities identified in your response to part (a), please state:
   (i) the amount, in kilowatt-hours of electricity, by which deliveries of electricity from that generating facility to the utility electric system can be reduced or curtailed by the utility during a 24-hour period; and
   (ii) the amount, in kilowatt-hours of electricity, by which deliveries of electricity from that generating facility to the utility electric system are currently being reduced or curtailed during a 24-hour period.

(d) for each of the generating facilities identified in your response to part (a) that does not generate electricity from hydropower, solar radiation, wind, geothermal, biogas, or biomass (a "non-renewable generating facility"), please state how much electricity generation, in kilowatt-hours of electricity, from the following types of generating facilities:
   (i) in-line hydropower generating facilities
   (ii) photovoltaic generating facilities
   (iii) concentrating solar generating facilities, or
   (iv) onshore wind generating facilities

Considering each such type in the aggregate, could be added or delivered to the utility electric system, without compromising the reliability of the utility electric system, by displacing reducing or curtailing electricity generation from such nonrenewable generating facility,

HELCO Response:

(a) On the HELCO system, delivery of electricity to the system at all generating facilities can be reduced or curtailed by the utility (in some cases, curtailment or reduction requires disconnection as there is no means for incremental load reduction). This is necessary to ensure reliable operation of the power system. Nearly all of the generator resources on the transmission system are dispatchable, and can be curtailed (through dispatch or a curtailment signal) or reduced (or stopped) by the system operator through the

SCADA/EMS system (for a discussion on HELCO's Must-Run generation see part b below). We will [or have requested] be requesting that the geothermal facility and Wailuku River Hydro are curtailed through operator instruction although we are requesting remote dispatch of these facilities to be added in the future. The majority of small distributed generators cannot be remotely monitored and controlled. For those resources, disconnection occurs manually at the generator location and these resources are disconnected only during restoration or maintenance activities. If the question is meant to address the types of generation which is subject to curtailment for excess energy on the HELCO system, the categories are as described on page 1 of Attachment 4 (Must-take Units). The units in this categroy include the following at this time:

1. Puna Geothermal Venture 30 MW.
2. Apollo (Tawhiri) 20.5 MW
3. Hawi Renewable Development – 10.56 MW
4. Wailuku River Hydro – 12.1 MW
5. Lalamilo – 2.2 MW
6. Puueo Hydro – 3 MW
7. Waiau Hydro – 1.1 MW
8. Sopogy (CSP)

Which facilities are curtailed will be dependent upon operating conditions such as system demand, production from various suppliers, derations, maintenance outages, etc. The first two suppliers are often curtailed off-peak under high variable production scenarios and under normal unit availability.

(b) It is assumed this question is with regard to excess energy curtailments as curtailments for other reasons are not subject to an order of curtailment. The principles by which must-take energy is curtailed are described in detail in Attachment 4 of the Companies'

Reliability Standards. Must run dispatchable generation is brought to minimum dispatchable load, with consideration for down-reserves, prior to curtailment of any resources. The generation considered must-run can change for future installations and for operating conditions.

Below is the operational curtailment policy instruction as of today, for HELCO's System Operators for excess energy curtailments. It does not include SOPOGY; that facility comes online only after calling the system operator as the remote curtailment interface is not yet completed. Note that this reference is specific to today's dispatch. For future generation additions, the mix of must-run generation and curtailable resources may change.

Normally during system off-peak periods, HELCO reduces the output of HELCO units and dispatchable Independent Power Producer units, prior to curtailing the as-available output. All cycling units are first taken off-line. Base load units are operated near their minimum regulating load limits (LFCMIN) so that the downward regulating reserve is not less than 9 MW. The AGC Regulating reserve alarm limit is 6 MW. For HELCO's typical dispatch, to determine excess energy curtailment, it is assumed the following dispatchable units are online and participating in regulation normally:

1. Hamakua Energy Partners which may be in dual train (2 CT CC) or single train (1 CT CC) depending on the near-term energy needs. The facility will be taken to 1 CT CC providing there will be sufficient down-time to account for the time it takes for HEP to shut down and start up, and considering the volatility of as-available energy, and the permit/contract limits on number of startups per day/month. In 2 CT CC the minimum under AGC is 18.5 MW, in 1 CT CC the minimum is 9 MW.
2. Hill 6 – Low limit on AGC (LFCMN) 15 MW
3. Hill 5 - Low limit on AGC (LFCMN) 8 MW

4. Puna Steam – Low limit on AGC (LFCMN) 6 MW

5. Keahole Combined Cycle - which may be in dual train (2 CT CC) or single train (1 CT CC) depending on the near-term energy needs. The facility will be taken to 1 CT CC providing there will be sufficient down-time to account for the time it takes for the second train to shut down and start up, and considering the volatility of as-available energy and permit limitations on numbers of startups. In 2 CT CC the minimum under AGC is 16 MW, in 1 CT CC the minimum is 7 MW (LFCMN).

In addition to these off-peak must-run units, PGV is operated 24 hours with a minimum take of 27 off-peak, and 30 on-peak, if PGV can produce it, unless curtailments are in effect. (See below for how PGV fits into curtailment priorities). Shipman is operated as must-run for certain scheduled shifts, and Keahole is dispatched according to the minimum generation required for the given load, beginning at 130 MW, as required to alleviate possible excessive overload of the 6800 line.

The Regulating Reserve Down (Reg Rv Dn) that is on the Generation Unit Status display or the Generation Area Status display is used to determine when to start the curtailment. This means that the units on-line will be above their minimum regulation limit (LFCMIN). The as-available that will be curtailed to maintain the Regulating Reserve Down (Reg Rv Dn) is no less than 9 MW. The curtailment order from first to last curtailed are:

1. Puna Geothermal Venture – Brought to normal schedule prior to curtailment. This is a curtailment of up to 3 MW (from 30 MW to 27 MW) during off-peak hours (10 pm to 7 am); schedule on-peak is 30 MW and PGV should be no higher than 30 prior to curtailment.

2. Apollo second phase (This is the Group B control) – Capacity of the facility is 20.5, but the amount of capacity in group B 13.5 MW. For group B curtailment, the reduction may begin at 20.5 MW to as low as 7.0 MW (the capacity of Group A) as needed.

3. Hawi Renewable Development – 10.56 MW capacity. This may be curtailed down to zero as needed.
4. Puna Geothermal Venture – The 5 MW above 22 MW is treated as as-available energy. If excess energy remains after curtailing 1-3, curtail this 5 MW (reduce PGV from 27 MW to 22 MW)

5. Wailuku River Hydro – 12.1 MW capacity. Wailuku may be curtailed for excess energy if steps 1-4 are insufficient. There is no remote control capability. The operator must be contacted, and in advance if possible. If the operator cannot be reached and curtailment is necessary, the tie breaker may be opened.

6. Apollo first phase (This is the Group A control) – 7 MW, which may be curtailed down to zero.

7. Lalamilo – 2.2 MW - there is no remote curtailment priority. It is unlikely the excess energy will require remote curtailment beyond 1-6.

8. Puueo Hydro – 3 MW - there is no remote curtailment priority. It is unlikely the excess energy will require remote curtailment beyond 1-6.

9. Waiau Hydro – 1.1 MW - there is no remote curtailment priority. It is unlikely the excess energy will require remote curtailment beyond 1-6.

Again, the Regulating reserve down is used to determine when to do the curtailment and when to release it. As load increases, the order is reversed and the units are picked up in sequence.

HELCO's non-typical dispatch. There will be times when HELCO might have to deviate from the typical dispatch shown above. As mentioned, at times there is not enough time to take combined cycle facilities from 2CTCC to 1CTCC. In the event that there are two base-load steam units offline (say, Hill 6 and Puna) we will operate Shipman in its place. Under some conditions, we may need to operate CT off-peak to provide a third unit for frequency regulation under AGC control. In such cases, where a unit is necessary for operational reasons, those units become "must-run", and the minimum load of the must-run units will be respected off-peak (along with 9 MW regulating reserve down) and the unit will not be taken offline.

(c)

i. See response to subpart b above.

ii. HELCO has no record of curtailed energy. This would require estimates of available energy to be provided by the supplier. Curtailments routinely occur at this time during off-peak conditions, from the top of the curtailment order through the Wailuku facility.

(d) If the identified facilities are variable and/or connecting to the distribution system, then an analysis would need to be done to assess the impact of these facilities, and requirements and/or measures defined so that the connection of such facilities would not contribute to the reliability issues from distributed and variable generation discussed in Attachments 2 and 3 of the Companies' Reliability Standards.

ZE-IR-107
For each utility electric system on the islands of Oahu, Hawaii, Maui, Molokai and Lanai:

(a) identify, by name, generation type and generating capacity, all generating facilities from which the delivery of electricity to the utility electric system can be reduced or curtailed by the utility during a 24-hour period;

(b) please state the order in which delivery of electricity from the generating facilities identified in your response to part (a) can be or is reduced or curtailed by the utility during a 24-hour period;

(c) for each of the generating facilities identified in your response to part (a), please state:

(i) the amount, in kilowatt-hours of electricity, by which deliveries of electricity from that generating facility to the utility electric system can be reduced or curtailed by the utility during a 24-hour period; and

(ii) the amount, in kilowatt-hours of electricity, by which deliveries of electricity from that generating facility to the utility electric system are currently being reduced or curtailed during a 24-hour period.

(d) for each of the generating facilities identified in your response to part (a) that does not generate electricity from hydropower, solar radiation, wind, geothermal, biogas, biomass (a "non-renewable generating facility"), please state how much electricity generation, in kilowatt-hours of electricity, from the following types of generating facilities:

(i) in-line hydropower generating facilities

(ii) photovoltaic generating facilities

(iii)concentrated solar generating facilities, or

(iv)onshore wind generating facilities

considering each such type in the aggregate, could be added or delivered to the utility electric system, with out compromising the reliability of the electric system, by displacing, reducing or curtailing electricity generation from such non-renewable generating facility.

MECO Response:

(a)

Generating Facility	Generation Type	Generation Nominal Capacity (MW)
Maui		
Kahului Power Plant	Steam	34
Maalaea Power Plant	Diesel and Combustion Turbines with Heat Recovery	212.1
Hana Substation DG	Diesel	2
Kaheawa Wind Farm	Wind	30
Makila Hydro	Hydro	0.5
Molokai		
Palaau Power Plant	Diesel	15.2
Lanai		
Miki Basin Power Plant	Diesel	10.4
La Ola PV Farm	Photovoltaic	1.2
Manele CHP	Diesel	0.8

(b) The order in which delivery of electricity from the generating facilities on Maui that can be or are reduced or curtailed by the utility during a 24-hour period for excess energy conditions is as follows:

1. Maalaea Power Plant (must run units down to minimum plus reserves)
2. Kahului Power Plant (must run units down to minimum)
3. Makila Hydro
4. Kaheawa Wind Farm

The distributed generators located in the Hana Substation are run only during emergencies or periods of maintenance on the Hana 23kV transmission line. HC&S is dispatched consistent with their PPA.

For Molokai, Palaau Power Plant is the only generating facility which delivery of electricity can be reduced by the utility (must run units down to minimum plus reserves) during a 24-hour period.

The order in which delivery of electricity from the generating facilities on Lanai that can be or is reduced or curtailed by the utility during a 24-hour period for excess energy conditions is as follows:

1. Miki Basin Power Plant (must run units down to minimum plus reserves)
2. La Ola Photovoltaic Farm
3. Manele CHP (can be reduced by 100kW during low load periods)

(c)

Generating Facility	Amount of Electricity that can be potentially Curtailed or Reduced in a 24-Hour Period (KWH)*	Amount of Electricity currently being Curtailed or Reduced in a 24-Hour Period (KWH)*
Maui		
Kahului Power Plant	Varies - Dependent upon system load, available units and regulating reserve requirements	Varies - Dependent upon system load, available units and regulating reserve requirements
Maalaea Power Plant	Varies - Dependent upon system load, available units and regulating reserve requirements	Varies - Dependent upon system load, available units and regulating reserve requirements
Hana Substation DG	Units not typically online	Units not typically online
Kaheawa Wind Farm	720,000	Varies - Dependent upon system load and power output from as-available units
Makila Hydro	12,000	Varies - Dependent upon system load and power output from as-available units
Molokai		

Palaau Power Plant	Varies – Dependent upon system load, available units and regulating reserve requirements	Varies - Dependent upon system load, available units and regulating reserve requirements
Lanai		
Miki Basin Power Plant	Varies - Dependent upon system load, available units and regulating reserve requirements	Varies - Dependent upon system load, available units and regulating reserve requirements
La Ola PV Farm	7,200**	Varies - Dependent upon system load and power output from as-available units
Manele CHP	800***	Varies - Dependent upon system load and power output from as-available units

* Based on Generation Nominal Capacity. Actual numbers will vary based on resource availability for as-available generation. Numbers shown are maximum values. MECO has not record of the amount of kWhs that have been or are curtailed from a facility.
** Based on 6 hours of solar radiation at full output in a 24-hour period
*** Based on reducing CHP by 100kW for 8 hours during low load periods (night time) but any curtailments will reduce the potential savings from the waste heat recovery.

(d) The amount of electricity generated, in kilowatt-hours of electricity, from the various types of renewable generating facilities that could be added or delivered to the utility electric system by displacing, reducing or curtailing electricity generation from such non-renewable generating facility is difficult to state due to the dynamic nature of an electrical system and the numerous combinations of factors that can influence the ability of an electrical system to integrate renewable generation without compromising the reliability of the electric system.

Variables that can affect the ability of an electrical system to integrate renewable generation without compromising the reliability of the electric system include:

1. System load
2. Types of firm generation available
3. Regulating reserve requirements
4. Level of power output from as-available generation
5. Volatility of as-available renewable generation on-line

Currently, it is already MECO's practice to lower the non renewable facilities to their minimums (respecting contractual provisions) prior to curtailing the as-available facilities.

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